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3 J-Power: Political Economy of the Fukushima Nuclear Catastrophe

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3.1 Personal Blind Spot

In hindsight one knows better, as the saying goes. But when trying to understand something that has already happened, practical science aims primarily to discover new contexts, reveal still unseen consequences and outline alternatives for acting. The objects of such science are contested terrain since the search for how and why something happened is pervaded by interests. And the searchers themselves are involved in power relations and conflicts. Ignoring and obscuring critical events help to protect predominant actors and their interest. Therefore, hindsight does not necessarily make smarter.

I have been living in Japan since 1991, researching and teaching about how companies in the automotive industries of Japan and Germany work on problems they themselves create in their pursuit of increasing profits through expansion of production and sales of fuel-burning automobiles. Like most of my fellow citizens, I had not seriously considered the way electricity is generated in Japan, the dangers and risks, critics' warnings and energy policy decisions. It took a disaster to become aware of it. This blind spot is worked on below to understand what happened, why it happened and what may happen in future. Apart from the personal search for meaning, the electric power generating and distributing business in Japan is a striking case of the close alliance between state and monopolistic corporations and the consequences that ensue for the vast majority of citizens, when this alliance dominates a central infrastructure. Similar to the field of automotive mobility and many other zones of public infrastructure, social services and private business, here, too, the transition to decentralised, flexible and sustainable forms of doing business has apparently been blocked by powerful players who cling to principles derived from industrial economy. Literally, the subject of this chapter is political economy.

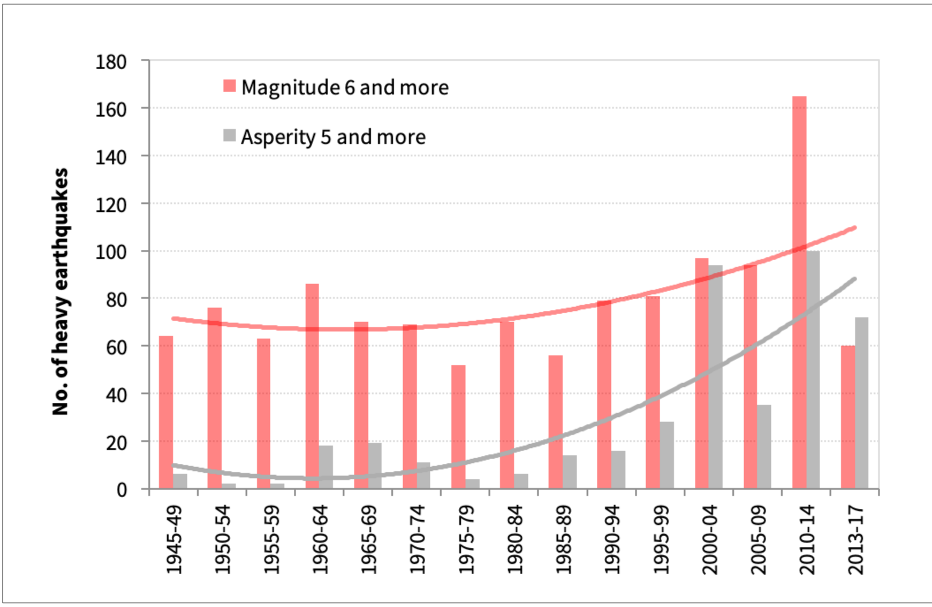
3.1.1 Earthquakes and Nuclear Power Plants in Japan

Japan's territory accounts for 0.1% of the earth's surface and 0.3% of the earth's land. From 1500 to 2017 10.0% of the world's earthquakes with a magnitude of 6 and more occurred in Japan (NOAA 2018). The number of severe earthquakes in Japan declined in the '70s, but it has risen again since 2000 and furthermore drastically since 2010 (chart 3.1). Almost the complete Pacific coastline and the northern half of the Sea of Japan coast are located along the boundaries of four huge continental plates. These plates move, generating large strain energy and releasing the accumulated stress as heavy earthquakes when rock mass fractures. Earthquakes due to energy accumulated between continental and marine plates are called subduction-zone earthquakes or ocean-trench earthquakes. As of January 2018, the Japanese Government Headquarters for Earthquake Research Promotion (HERP) estimates the probability of earthquakes in the range of magnitudes 7-9 within the next 30 years for the Nankai and Suruga Trough (southwest-south of Kyūshū, Shikoku, Kinki and Chūbu) to be 70-80% (magnitude 8-9), for the Sagami Trough (south of Kantō) 70% (magnitude 7) and 0-5% (magnitude 8), for the Ibaraki off coast area over 90% (magnitude 7), for several Tōhoku off-coast areas 50-90% (magnitude 7; magnitude 8: 4-30%) and for several areas southwest of Hokkaidō 8-80% (magnitude 8) (HERP 2018). Based on its 2017 Seismic Activity Projection Model, the National Research Institute for Earth Science and Disaster Resilience (NIED) indicates 22 subduction-zone earthquakes of a magnitude range between 6.8-9 to occur with a probability of 0-73% within the next 30 years and of 0-93% within the next 50 years (NIED 2018).

Furthermore, Japan's inland territory sits on a cluster of active faults (*katsudansō*), which have been created by earthqakes in the upper layers of the earth mantel and are themselves prone to so-called inland earthquakes.[1] At the end of the '90s, more than 1,600 active faults were known (Yamazaki 1997, 494). In 2009, the Earth Faults Database of the National Institute of Advanced Industrial Science & Technology (AIST) detected 548 faults zones or segments of varying sizes. As of February 2018, AIST indicates 583 active fault zones or segments based on data from FY2015 (AIST 2018). As of January 2016, the number of known active faults in Japan was estimated

1 Ishibashi 1997, 720-1; 2008, 54; Watanabe M. 2010, 35; Watanabe et al. 2012, 125-34.

Chart 3.1 Heavy earthquakes in and around Japan (CY)



Source: Author, based on JMA (2018)

at ca. 2,000. Among them, 100 fault zones with a high concentration or density of faults were chosen by HERP and broken down into segments. 200 locations among them were evaluated to have a probability of a heavy earthquake (of magnitude 6.8 and more) to occur within the next 30 years. 34 locations were assessed as having a high probability of 3% and more. Another 50 locations were found to have a 'rather high' probability of 0.1%-3% (Masumitsu 2016, 92-7). As of January 2018, 36 locations are ranked by HERP (2018) as zones with a high probability of 3% and more. Based on its 2017 Seismic Activity Model, the National Research Institute for Earth Science and Disaster Resilience (NIED) identifies 260 major active fault zones and 151 other active faults (NIED 2018). There are serious doubts among experts about whether and how precisely probabilities of earthquake occurrence can be calculated (Geller 2011). But there is no doubt that Japan is one of the most active seismic zones in the world and that Japan has entered a long-term period of increased seismic activity since 2000.[2]

At the beginning of March 2011, 17 nuclear power plants (hereafter NPP) with 54 reactors (hereafter NPR) and a generating capacity of 49 gigawatt

2 Ishibashi 1997, 720-4; 2008, 52-60; Kamata 2015, 23, 28, 43; 2016, 8-9; 2018, 161-5.

(GW) were in operation in Japan. They represented 12% of all NPRs worldwide and 13% of the world's nuclear power generation capacity. As of the end of 2016, the International Atomic Energy Agency (IAEA) indicated for Japan 42 NPRs in operation (equivalent to 9.4% of all reactors worldwide) with an installed nuclear power capacity of 39.7 GW (equivalent to 10.2% of the global capacity) (IAEA 2017, 136). As of early June 2018, the Japan Atomic Industrial Forum (JAIF) accounted 39 NPRs with a generating capacity of 38.6 GW as currently existing nuclear power generating stock. 25 NPRs (with 24.8 GW) had applied for assessment, among which 14 NPRs (with 14.3 GW) saw their assessment completed. 12 NPRs (with 11.6 GW) got conversion or rebuild approved; 8 NPRs (with 8.0 GW) are operating (JAIF 2018). As of mid-June 2018, the METI indicated 8 NPRs permitted for operating, 6 NPRs with completed procedures for re-permission, 12 NPRs under evaluation for permission renewal, 16 NPRs without application for permission renewal and 18 NPRs to be decommissioned (METI 2018d).

The average age of all Japanese NPRs was 24.3 years in March 2011; 29 of them were older than 25 years and 19 older than 30 years (Ino 2011, 659). At the end of 2016, 13 reactors were older than 40 years, another 18 reactors were older than 30 years (chart 3.2). But the approved standard lifetime for pressurised-water reactors (PWR) is 30 years and 40 years for boiling water reactors (BWR). This means that Japan's stock of NPR is highly aged.

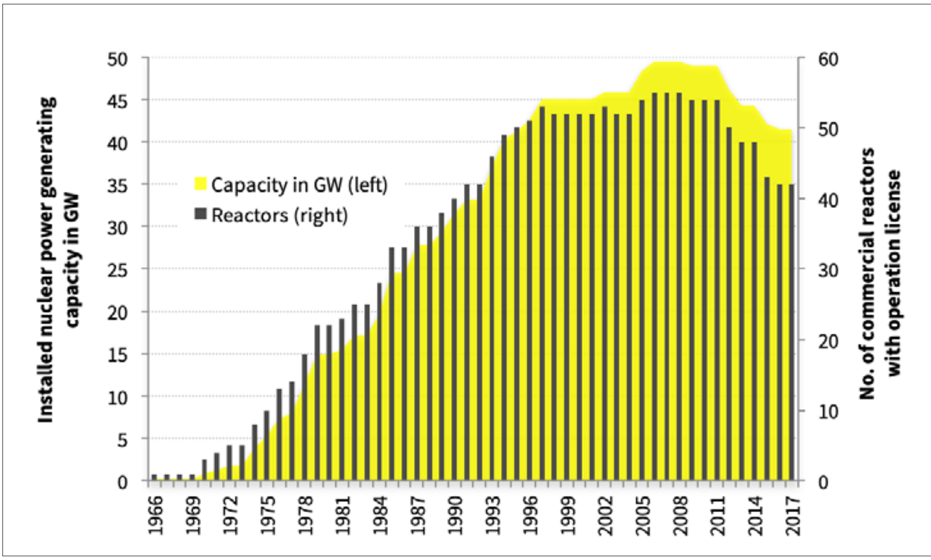
The number of reported issues ('troubles or accidents and safety relevant quality issues') at Japanese NPP/NPRs reached a first peak in the early '80s. In the second half of the 2000s, the total number of reports increased again and peaked preliminarily (chart 3.3).

Heavy earthquakes had severely damaged nuclear reactors in 2007 and 2009 and forced emergency shutdowns.[3] In 2006, METI tightened the criteria for assessing whether nuclear reactors are earthquake-proof. But METI accepted the self-audits of the NPP/NPR operators, according to which all (self-)tested NPP/NPRs were earthquake-proof (Hirose 2010, 165-75). Before the Fukushima nuclear disaster had occurred (hereafter referred to as 3/11), the public authorities in charge of regulating and overseeing nuclear power generation did not have any reason to correct their assessment that the likelihood of a maximum credible accident (MCA) or nuclear worst case scenario due to an earthquake amounted to only 1:1 million to 1:10 million per year (Ban 2011, 167).[4] In October 2011, Tōkyō Electric Power Company (TEPCO) published the result of their own risk assessment, carried out after the Fukushima disaster. According to this, the likelihood of a meltdown has increased from 1:10 million to 1:5,000 or

3 Yamaguchi 2007, 1156-9; Ishibashi 2008, Hirose 2010, 57-62.

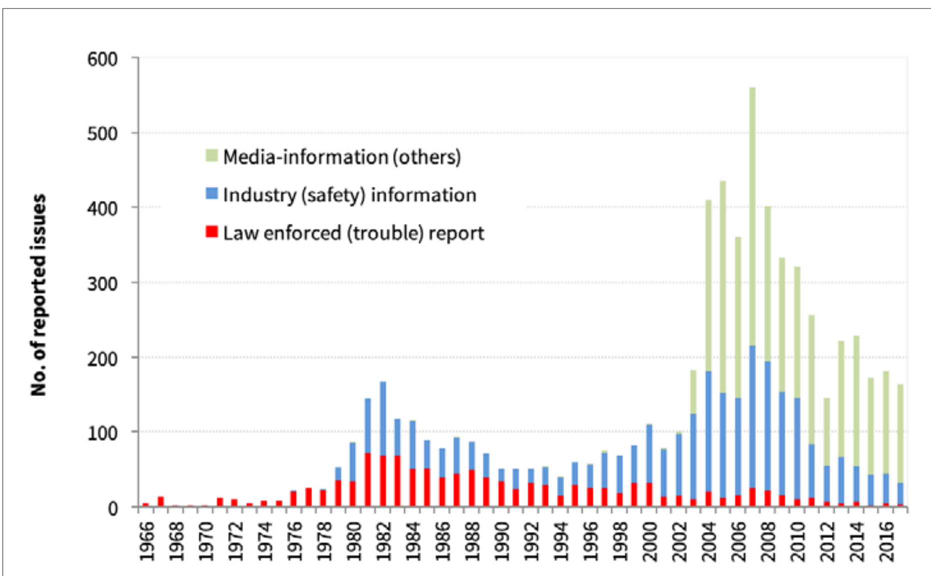
4 For the historical development of probabilistic risk assessment in the US see Wellock 2017.

Chart 3.2 Stock of NPR and generating capacity in Japan (CY)



Source: Author, based on JNES 2013; METI 2018a, 2018b

Chart 3.3 Reported troubles, safety and other issues at Japanese NPP/NPRs (CY)



Source: Author, based on NUCIA 2018

0.02% per year (cf. `www.asahi.com`, dated 20 October 2011). However, the result of a simple retrospective calculation (as of 2012) results in one meltdown per 500 NPR running years or an occurrence probability of 0.2%.[5]

In August 2009, METI approved the continuation of operating reactors no. 1 of the NPPs in Tsuruga and Mihama until 2016 and in Fukushima until 2021. These NPRs had been in operation since 1970 and 1971, thus exceeding the period of 40 years planned by their builders by 6-10 years respectively (Ino 2007, 1124; 2011, 658; Tanie 2011, 55). In addition to seven more reactors older than 40 years, these three reactors were shut down or destroyed by accident and are now decommissioned. But in April 2015 Kansai Power Electric Company (KEPCO) applied for permission to operate reactors nos. 2 and 3 of the Takahama NPP and reactor no. 3 of the Mihama NPP for another 20 years, exceeding the originally set lifespan of 40 years by 50% (AEC 2017, 155). In June and November 2016, these permissions were given by the National Regulation Authority (NRA) despite continued warnings from experts of the risks of operating nuclear reactors beyond their designed lifespan (Ino 2016a, 2016b). At the end of February 2012, 2 NPRs were treated as reactors under construction, one in Shimane and the other one in Ōma. At the end of 2016, government reports indicated even 3 NPRs as being under construction: TEPCO's NPR no. 1 at the Higashidōri NPP was re-added to the former two (AEC 2017, 152).[6]

In 2010, Japan's government had decided to revise its energy master plan. At least nine new nuclear reactors were to be built by 2020 and another five by 2030. NPR utilization was projected to be increased from 61% (in 2007) to 85% (in 2020) and 90% (in 2030) and the share of nuclear power in electricity generation to be raised from 30% (in 2010) to 53% (in 2030) allegedly in order to reduce Japan's energy dependence from imports of fossil fuel, produce electricity cost-effectively and limit the emission of greenhouse gases (METI 2010, 9). The revised energy master plan of 2014 repeated these arguments in favour of nuclear power generation, foregrounding the necessity to continuously increase operational safety and re-establish the conditions for stable commercial use of nuclear power, but it did not provide a specific definition of the future volume and composition of electricity supply. The master plan has been in revision since August 2017. Meanwhile, METI released a long-term energy

5 Previous three core meltdowns divided by previous 1,406 NPR running years (54 NPR × average age 24.3 years + 94 years of NPR shutdowns) = 0.2% = 1 core meltdown per 500 NPR running year (see also § 3.3).

6 Newspaper *Yomiuri* reported that, due to 3/11 and its own critical financial situation, TEPCO had decided on 30 November 2011 to discontinue the construction of NPR no. 1 in the Higashidōri NPP, started in January 2011 (planned start of operation: 2017). The decision to build NPR no. 2 (planned start of operation: 2020) was supposed to be canceled soon afterwards (*Yomiuri Online*, 1 December 2011).

demand-supply vision in July 2015, according to which the share of nuclear power in electricity generation is projected for 2030 at 20-22%, equivalent to 213 TWh (METI 2015c, 7).

3.1.2 The 'Nuclear Earthquake Disaster' of March 2011

In March 2011, an earthquake of magnitude 9 shook north-eastern Japan. Shortly after a powerful tsunami hit the coast and buried countless people, houses and villages. As a result of accidents or emergencies, 25 NPRs with a generation capacity of 29 GW (equivalent to 12% of Japan's total installed generating capacity at the time) were shut down (Motoshima 2011, 46). These included 14 NPRs at the NPPs of Onagawa, Higashidōri, Fukushima-1, Fukushima-2 and Tōkai-2. In four of the six reactors at the NPP Fukushima-1, explosions occurred during the first four days after the earthquake. Since then, the cores of reactors nos. 1, 2 and 3 have been melting. In June 2011, the Japanese government announced that 1.6 × 1,017 Bq of iodine 131, 1.5 × 1,016 Bq of caesium 137 and 1.1 × 1,019 and Bq of xenon 133 had leaked from the damaged NPR, while an independent estimate assumed 3.5 × 1,016 Bq caesium 137 and 1.7 × 1,019 Bq xenon 133 (Brumfield 2011, 435-6). This independently estimated volume equals 41% and 260% of the respective leakages caused by the 1986 maximum credible accident (MCA) in Chernobyl (IAEA 2006, 19). Immediately after the 3/11 earthquake, 8.71 million households in north-eastern Japan were out of electric power. In the supply region of TEPCO, blackouts occurred 32 times and lasted for several hours from 14 March 2011 onwards for ten days (Motoshima 2011). Japan's central government and Fukushima-1 NPP operator TEPCO claimed that this could not have been anticipated, because it was the extreme and unpredictable magnitude of the earthquake and the tsunami that rendered power generation and cooling systems at many NPRs inoperable (*The Asahi Shimbun*, 1 December 2011, 1). But as early as 1990 researchers of NPP/NPR operator Tōhoku Denryoku (Tōhoku EPCO) had shown that in the 9th century a heavy earthquake had triggered a tsunami whose height was several meters above the officially accepted maximum of 6 meters for Japanese NPP/NPRs. Under the legitimate assumption that such a thing could happen again at any time, scientists had repeatedly warned that there is a severe lack of protection against heavy earthquakes and tsunamis in Japan (Geller 2011, 46-63; Kamata 2015). Critical experts and former NPR specialists like Tanaka (2011a, 2011b, 2011c, 2012), Gotō (2011a, 2011b) and Watanabe (2012) suppose that it was not the tsunami and the related power failure, but the earthquake that destroyed the cooling water pipes in NPR no. 1 and the cooling and pressure regulating steam pipes in NPR no. 2, effectuating the meltdowns and hydrogen explosions. Gundersen (2012a;

2012b, 21-55) is of the opinion that after the cooling failure hydrogen was produced in NPR no. 1, and that the consequent pressure prompted the top seal of the reactor pressure vessel to leak and let hydrogen flow into the reactor building, where it exploded. In addition, TEPCO's top level emergency command, fearing the loss of more NPRs, refused to flood NPRs nos. 2 and 3 with seawater immediately after the emergency cooling had failed (Yamaguchi 2011, 2012). With a multiple Loss of Coolant Agent (LOCA), it finally came to the meltdown in NPRs nos. 1-3 and the leakage of large amounts of radioactivity.

One of the aftershocks interrupted the regular and, in parts, the emergency power supply in the NPPs Onagawa and Higashidōri in April 2011 (Gotō 2011a, 429). Heavily criticised for his crisis management, the then prime minister Naoto Kan urged NPP/NPR operator Chūbu Electric Power (CEPCO) to shut down at least the particularly earthquake-prone Hamaoka NPP in May 2011 (Shushō Kantei 2011). Under the condition that it would be recommissioned in compliance with new safety requirements to come, CEPCO disconnected NPR nos. 4 and 5 from the network.

By March 2012, only one among Japan's total stock of 54 commercial NPRs was in operation, 38 were in control reviews and 14 were down due to accident-related damages and inoperability (CNIC 2012a). But already in August 2011 NPR no. 3 of the NPP Tomari and in November 2011 NPR no. 4 of the NPP Genkai were restarted, although the latter ran only until an accident in December 2011. In March 2012, the government signalled its intention to intervene into the permission procedure in favour of recommissioning NPRs nos. 3 and 4 of the NPP Ōi, which had been tested for safety after 3/11 in line with previous regulation procedures (*The Asahi Shimbun*, 24 March 2012, 1). At any rate, all NPRs in Japan were out of operation in early May 2012 for the first time in 42 years.

Already in 1997, earthquake researcher Ishibashi had pointed out that after a relatively calm period since the mid-'60s, the 1995 earthquake in Kōbe instigated a new period of heightened seismic activity. This would increase the likelihood of heavy earthquakes and the danger that such an earthquake irreversibly destroyed NPP/NPRs and with them large parts of the country (Ishibashi 1997, 720; 2008, 54, 57). Ishibashi coined the term *genpatsu shinsai* (nuclear earthquake disaster). In his view, METI had superseded the danger and avoided eventual damage control, let preventive measures. Therefore, Ishibashi demanded the immediate shut-down of all Japanese NPRs, but especially the earthquake-prone NPP in Hamaoka (Ishibashi 1997, 721-3; 2008, 57).

3.1.3 Historical Parallels

In the early ’80s, a research group at Japan’s Military Academy analysed pivotal battles lost by the Imperial Japanese Army during World War 2. The researchers identified as the most decisive cause of defeat a deplorable combination of features related to strategy and organizational culture, prevalent not only in the former military, but also, according to them, in many contemporary Japanese firms: unspecified, fuzzy objectives, short-term and dominantly tactical decision-making, inductive thinking, underdeveloped option-building, inconsistent and opportunistic response, collectively dispersed liability, organizational integration through interpersonal-relations and subordination, short-circuited interventions, personalised evaluation and promotion according to attitude and process participation (Tobe et al. 2001, 338). The title of their book was *The Nature of Failure*. The assumption that the basic patterns of goal determination and achievement as well as the implicit rules of behaviour are still in place was reconfirmed by 3/11. Yoshioka (2011d, 131-4) attributes the failures of the Japanese state during the Fukushima disaster to the fact that worst-case scenarios are not simulated, respective lines of order and report not determined, and that warnings stay unheard and corrections delayed due to unrealistic plans.

The above listed features seem to distinguish traditional Japanese organisations from those that have to work under unpredictable conditions, where any mistake can cause catastrophic consequences, the so-called high reliability organisations. Such organisations draw the attention of their members to two things: first, always to expect a deviation from the expected and consequently search for early signs of error, refuse simplistic explanations, pay attention to local peculiarities; and second, after the occurrence of an unexpected case to keep functioning under extreme conditions, learn self-critically and respect local expertise (Weick, Roberts 1993; Weick, Sutcliffe 2001).

In his last publication, Jinzaburō Takagi, nestor of Japan’s Anti-Nuclear Energy Movement, asked why repeated nuclear accidents had not led to clarifying responsibilities and correcting errors. He found the answer in unquestioned patterns of behaviour, practiced by the majority of Japanese society: open discussion, critical thinking and ethical conviction are chronically lacking (Takagi 2000a, 33-5). Instead, the dogma of a coercive community of fate, authoritarianism and totalitarian nationalism have been prevailing (47-67). A consideration of the wider public, which could guide the thinking and acting of responsible members of society, is missing (98-121; Saitō 2015, 324-9) as is aspiration to critical self-reflection (Takagi 2000a, 124-56).

In 2009, Hidenori Kimura, a professor in advanced engineering and control technologies, contended that the supposedly high competitiveness of Japanese manufacturing companies is a myth. Mass production and consumption have made industrial processes so complex that they can be measured, steered and controlled only abstractly. The modernisation of Japan, however, was characterised by basic lack of dealing with abstraction, due to a chronic shortage of capital, industrial technology and scientific knowledge. Industrial machinery was limited to specific areas and often used as a mere tool, empirically and incrementally adapted to labour-intense applications. In Kimura's view, Japan's defeat in World War 2 was caused by a craft-based military and economic system, inferior to the large-scale mass industrialised and science-based US-American one (Kimura 2009, 97-142). In contradistinction, the commercial use of nuclear energy manifests the post-mechanical revolution of science and as such the limits of traditional ways of thinking and acting (152). But in contemporary Japan attempts prevail to deal traditionally with complex processes and developments, which exceed the logic of classical mechanics based as it is on labour-intense optimisation. Similar to Ishibashi (1997, 2008) and Tobe et al. (2001), Kimura (2009), too, draws parallels to World War 2 in regard to how organisations and experts in business, science, education, politics and mass media ignore deficits and dangers, overestimating traditional models or even promoting them nationalistically (12-15).

Ishibashi coined the term 'nuclear earthquake disaster' in 1997 against the backdrop of a big difference between Europe and Japan. Since the disaster of Chernobyl in 1986, there had been public debates and political movements, focused on how to cope with the immense risk of nuclear power generation and how to phase out eventually. In Japan, on the other hand, the situation was different. Despite some public debate and local civil movements, the government maintained its promotion of nuclear energy and rural regions embraced the inflow of private capital and public subsidies as well as employment opportunities generated by local NPPs and the related businesses. According to Ishibashi, the social paralysis, which hampers any step towards a nuclear phase-out, resembles Japan's situation in view of its defeat in World War 2 (Ishibashi 1997, 724): people were aware of the inevitability but not able to take another path. In 2008, Ishibashi also described the earthquake-related reactor accident at the Kashiwazaki NPP in 2007 as a message from nature, not unlike the Potsdam Agreement which was a last call to capitulate, that is, to tackle the nuclear phase-out (Ishibashi 2008, 52). Otherwise, Japan would encounter a third nuclear disaster after the atomic bombings of Hiroshima and Nagasaki. But, according to Ishibashi, Japan's electric power producers, the government and connected scientists have ignored the signals and justified the previous course. That nuclear power plants are indispensable and safe has been spread by mass media and believed by the majority of Japan's population just as the war-time pronouncements by the Imperial Army's headquarters (Ishibashi 2011c, 126-7). In 2011, Ishibashi wrote that the peculiar constitution of Japanese society, which had led to war and defeat, found its post-war equivalent in the illusion that nature and earthquakes could be controlled (Ishibashi 2011b, 411).

The Fukushima nuclear disaster was the result of a social failure: organisations in politics, business and science as well as their representatives had ignored the dangers of nuclear power generation, manipulated assessments and suppressed criticism. The question arises as to who gained. Under capitalist conditions, the interest in generating profits or return on investments must be assumed to be of central importance. Obviously, however, the high risks and actual costs of nuclear power generation have hardly been included and sufficiently considered by Japan's electric power companies. The question of why interest in nuclear power generation has become so dominant in Japan is investigated below by interrelating research from the fields of Japanese economic, political, business and technological history, including the related statistics.

3.2 Cui Bono? Interests, Power and Nuclear Power Generation in Japan

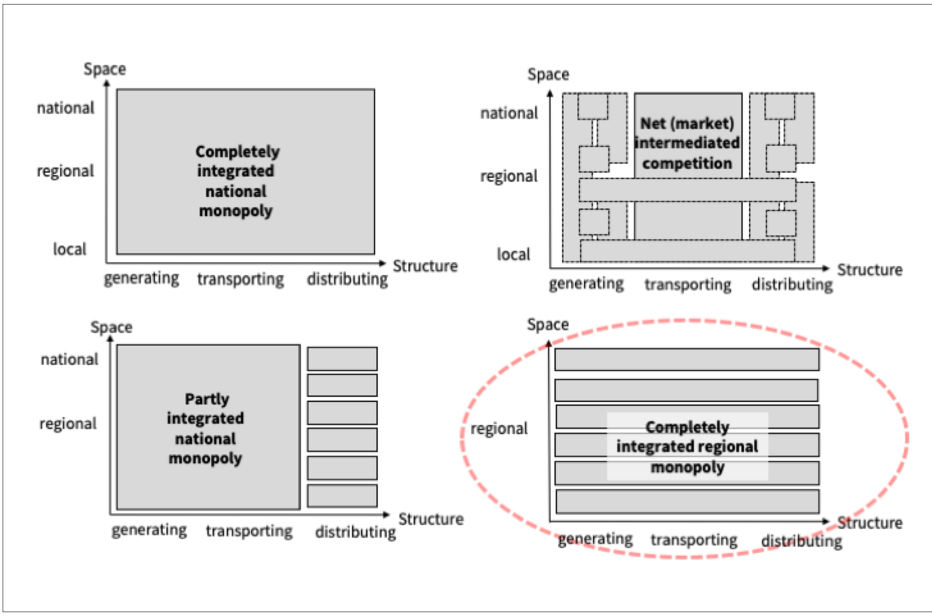
3.2.1 Ownership and Business Model of the Electric Power Industry in Japan

In Japan the generation, transmission and distribution of electricity is in the main vertically integrated and organised as a private-sector business of regional monopolies. These monopolies are subject to state supervision. Electricity prices are to be approved by METI. This hybrid organizational form was determined in 1950 by the GHQ against the will of the Japanese government and the conservative ruling parties. They preferred the wartime model of a national monopoly, with only the final distribution handed over to private companies. The GHQ, however, saw this as an attempt by the Japanese political class to restore state-monopolistic structures. It ordered the Japan Electricity Generation and Transmission Ltd. (*Nihon Hassōden Kabushiki Gaisha*), founded in 1942, to be split into nine private-sector regional monopolies and subjected those to state price control (Kikkawa 2004b, 166-91) (fig. 3.1).

This means that the electricity price[7] is set by the central government and outside the scope of individual entrepreneurial decisions, at least formally. Under such conditions, private power companies would be interested in keeping costs as low as possible, while increasing production and

7 Electricity price is defined as the sum of the variable and fixed costs per electricity unit required for the provision of electricity and an appropriate return on the assets used for this purpose.

Figure 3.1 Structures of electric power business

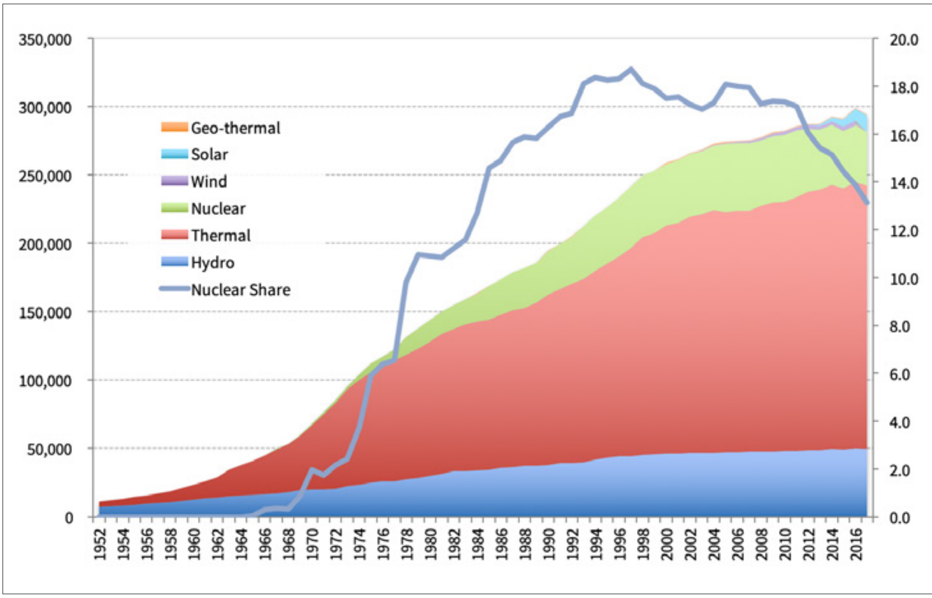


Source: Author

consumption of electricity and maintaining the balance between both. In the electricity industry costs occur from financing investments, the construction of facilities or the corresponding write-downs, their subsequent elimination and related provisions. Costs incur also from the purchase of fuels, the operation and maintenance of installations, the disposal of waste and exhaust gases as well as the related taxes. The biggest positions are depreciation and fixed operating costs. They do not depend on fluctuations in the production and consumption of electricity.

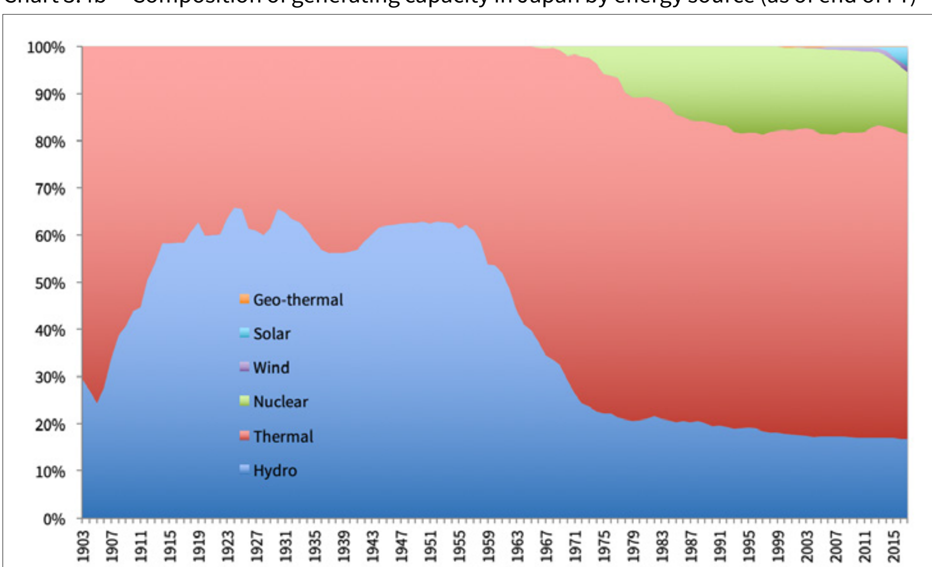
From a business point of view it is therefore vital to reduce the fixed costs, i.e. to keep the investment and depreciation costs for power plants and electricity grid as low as possible and the utilization of both assets as high as possible, without endangering the stability of the electricity supply. Balancing out the production and consumption of electricity means that production needs to be adjusted to changes in consumption. Electricity companies use different types of power plants for this purpose: to cover the baseload they use power plants that can only be started up or shut down slowly and at high cost and are efficient only in continuous operation, whereas, to cover peak loads, they use power plants that can be started up and shut down faster and at lower cost. From the ’30s to the ’60s, the

Chart 3.4a Electric power generating capacity in Japan (as of end of FY) by energy source (MW, left) and share of nuclear capacity (%, right)



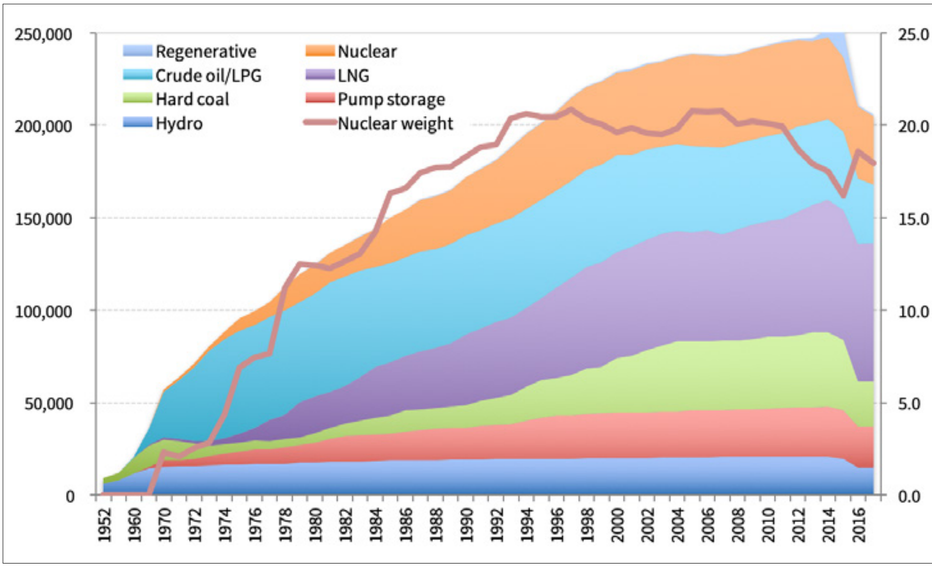
Source: Author, based JBHI 2018; METI 2018b

Chart 3.4b Composition of generating capacity in Japan by energy source (as of end of FY)



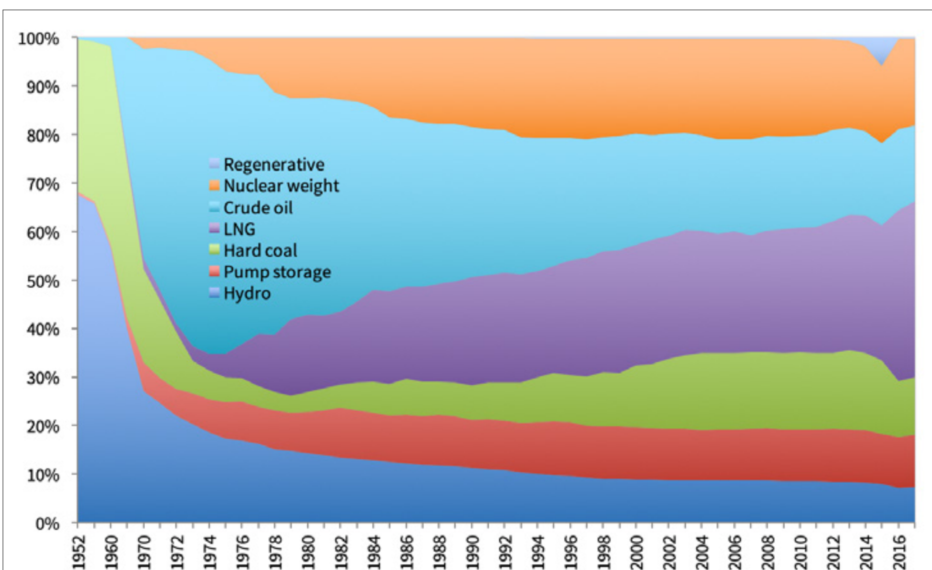
Source: Author, based on JBHI 2018; METI 2018b

Chart 3.5a Installed electric power generating capacity (as of end of FY) at general utilities by source (MW, left) and share of nuclear capacity (%, right)



Source: Author, based on FEPC 2018; METI 2018c

Chart 3.5b Composition of installed electric power generating capacity at general utilities by energy source (as of end of FY)



Source: Author, based on FEPC 2018; METI 2018c baseload was covered by large hydroelectric power plants, while coal-fired thermal power plants were used during peaks (Kikkawa 2004a, 133-43) (charts 3.4a-b).

Regional monopolies can only grow if production and consumption in their own supply area increase. Increasing the production of electricity beyond a maximum utilization of existing capacities requires investment in new power plants. These must be cheaply financed with outside capital, used to full capacity and quickly amortised. High economic growth in the ’60s led to an explosive increase in demand for electricity and, relatedly, the danger of chronic shortage. Japan’s electric power companies, for their part, initially sought to achieve a mix that was both capital and cost-saving: newly built oil-fired thermal power plants were to cover the baseload, while new pumped-storage power plants and old hard coal-fired thermal power plants were to cover the peak load. To be operated efficiently, thermal power stations can be fired with cheap crude oil. They are quicker to erect and require less investment than hydroelectric or coal-fired thermal power plants. However, the construction of new power plants met with growing resistance among the population due to escalating air pollution (Kikkawa 2004a, 237-49) (charts 3.5a-b).

In addition, the investment behaviour of power companies stood in sharp contrast to the government’s political and industrial policy, which was aimed at expanding the heavy industry through economies of scale and, to that effect, increasing electricity production. Thus, covering the baseload with hydroelectric power plants and the peak load with thermal power plants, which were to be fired with domestic hard coal, received preferential treatment (Kikkawa 2004a, 271-2, 295-7). As early as 1952, the government had founded a company to build up and operate electric power generation capacity (*Dengen Kaihatsu Kabushiki Gaisha*). This was to run hydroelectric and thermal power plants, i.e. to enter a field where private companies acted with reserve. In order to promote domestic plant and heavy machinery construction, the then MITI (today’s METI) urged owners and operators of new power plants to import only the pilot plants and commission all other to domestic plant manufacturers or builders (Kikkawa 2004b, 259-63).

3.2.2 State Political Interests: Hidden Military Budget?

> From 1937 to 1941, the world's largest battleship *Yamato* was built in strict secrecy in the Kure Shipyard (Hiroshima Prefecture). Its construction costed 137.8 million JPY, or 1.8% of Japan's government spending 1938-1941. From 1942 to 1943, the *Yamato* was the flagship of the Japanese Navy in WW II. In April 1945, it was sunk off the coast of Kagoshima by US Navy aircraft. In August 1945, a US-American atomic bomb destroyed Hiroshima, killing more than 120,000 people. Located 18 kilometres from Hiroshima, in Kure's Shipyard No. 2, where once the *Yamato* turrets were built, Hitachi assembles and tests nuclear reactor pressure vessels today.'
>
> (Katsuhisa Miyake, *Nihon o horobosu denryoku fuhai*, 2011, 283-6)

Progress in nuclear conversion in the UK, Canada, France and the Soviet Union unsettled US president Dwight Eisenhower (Yamaoka 2011, 46; Suzuki 2006, 126). Pushed for commercial liberalization by the US nuclear industry, among other things, he delivered his 'Atoms for Peace' address to the UN in 1953. It was labelled as an appeal for the peaceful use of nuclear power. Yet, it did not imply the renunciation of military use.[8] In 1949, the Soviet Union demonstrated the functionality of its own atomic bomb, breaking the US monopoly on nuclear weapons technology. As a result, the US government tried to integrate their allies into the now nuclear arms race. For the civilian use of nuclear power, fissionable and weapons-grade uranium 235 must be enriched. Neutron exposure of uranium 238 generates weapons-grade plutonium 239.[9] To build NPPs, producing nuclear fuel and disposing of it or reprocessing it require huge investments. In view of the quantitative nuclear arms race, it was in the interest of the military to industrialise the production of weapons-grade uranium or plutonium. This, in turn, corresponded to the economic interest of electric power companies to rapidly amortise high investments and increase profits through economies of scale.[10] NPP manufacturers or builders gained export oppor-

8 Suzuki 2006, 12; Tanaka, Toshiyuki 2011, 1285; Hirata Kōji 2011, 1275-6.

9 Suzuki 2006, 34; Takubo 2011, 165-76; Fujita 2011, 1270-1. Officially, Japan had 30.1 t of fissionable plutonium at the end of 2010, 6.7 t in Japan and 23.4 t in the UK and France for reprocessing (AEC 2011a). As of late 2016, Japan owned 46.9 t, 9.8 in Japan and 37.1 in the UK and France (AEC 2017, 112). According to the IAEA, 8 kg of fissionable plutonium are required for a nuclear warhead (IAEA 2001). If so, the amount of fissionable plutonium owned and held domestically by Japan in 2010-2016 corresponds to a quantity of 837 (2010)/1,225 (2016) nuclear warheads. However, estimations from 2010 state that the newer generation of warheads needs only 4 kg (Sanger 2010).

10 This means the reduction of unit costs associated with the increase in production volume.

tunities as well as chances of follow-up business related to the licensing and maintenance of NPPs. Growing demand for nuclear fuel led to rising prices and profits in uranium mining and uranium enrichment.[11]

US-American nuclear bombs destroyed Hiroshima and Nagasaki in 1945, killing hundreds of thousands of people, and in 1954, Japanese fishermen were fatally contaminated during a US-American hydrogen bomb test on the Bikini atoll (Yamazaki 2011, 1277-83). In this respect, there should have been reasons for a general rejection of nuclear technology among the Japanese population. Nevertheless, the promises of its peaceful use were widely accepted by the majority, ranging from right-wing revanchist and conservative to liberal-democratic and socialist positions (Yamaoka 2011, 13, 98). But the political initiative for promoting nuclear power was taken by those whose ambitions had failed with the defeat in World War 2. In the access to nuclear technology they saw the opportunity to restore their own position and bring Japan back into the circle of powerful states (Suzuki 2006, 29, 30; Yamaoka 2011, 11, 14).

Supported by the US government and its secret service, two key figures came to excel, the former naval officer, right-wing conservative politician and later prime minister Yasuhiro Nakasone and the later founder of the private television station Nippon TV and entrepreneur of the Yomiuri media group, who had been convicted of war crimes in 1945, Matsutarō Shōriki. They pushed for the immediate use of nuclear power in state economic policy and legislation (Arima 2011; Tateno 2011, 1287-8). Tackling cleverly with prime ministers Shigeru Yoshida (1946-47, 1948-54), Ichirō Hatoyama (1954-56) and Nobusuke Kishi (1957-1960), Nakasone and Shōriki received important cabinet and committee positions from the mid-'50s onwards. In 1954, Nakasone pushed the state funding of nuclear research (i.e. NPP development) and in 1955-1956, in the form of an initiative by a parliamentary member, the laws necessary for the institutionalisation, realisation and financing of the civilian use of nuclear energy (Yoshioka 2011c, 1296-7). While Nakasone regarded nuclear technology as being in the interest of the state, Shōriki represented the private sector (Yamaoka 2011, 99; Yoshioka 2011c, 1297). As their political influence and the prospects for commissions and state subsidies grew, they became interesting for and generously financed by big business (Onizuka 2011, 130-47).

In 1964, China tested a nuclear bomb for the first time. As a result, the Japanese government re-examined the possibility of producing and owning its own nuclear weapons. In the end, however, it saw itself unable

11 Onizuka (2011, 12-36) sees in Victor Rothschild (1910-1990) the driving force behind US nuclear policy and its expansion to Japan, because as the majority shareholder of Rio Tinto he benefited most from the military and civil use of nuclear power and the resulting boost in demand for uranium. The uranium price actually rose from 17 USD per kg (1972) to over 110 USD per kg (1980) (OECD 2006, 35).

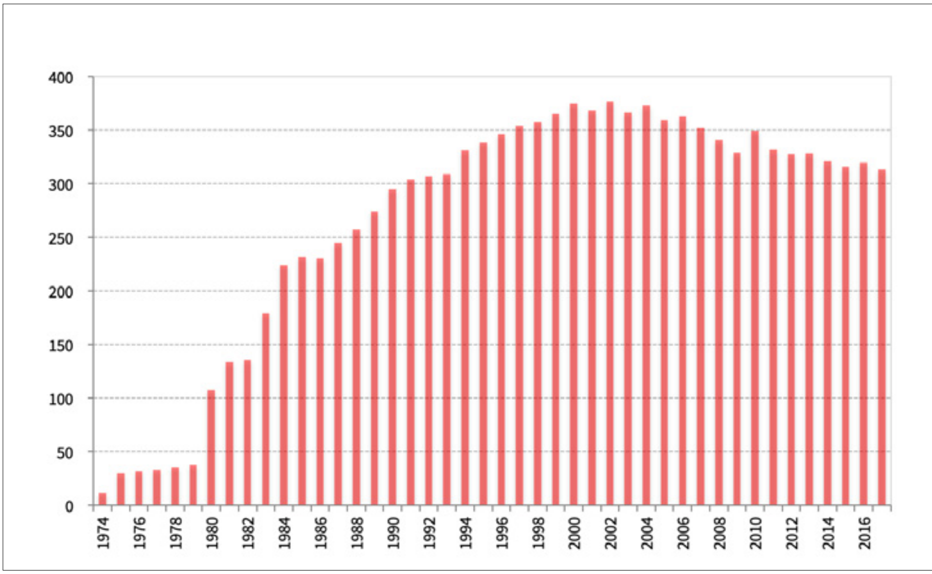
to produce nuclear weapons on a militarily relevant scale at justifiable cost. Japan had to renounce this option anyway, when it joined the Non-Proliferation Treaty (NPT) in 1970 and went under the 'nuclear umbrella' of the US. With respect to the civilian use of nuclear technology, Japan was subject to International Atomic Energy Agency (IAEA) supervision and licensing by the US, although it secured limited reprocessing rights and retained the technological conditions for the production of nuclear weapons (Suzuki 2006, 191-3).

In 1961, the Japanese government passed the Act on Compensation for Damage Caused by NPP. Responding to foreign demands, NPP builders were exempted from any liability. Initially, operators had been held fully and indefinitely liable except in case of natural or social catastrophes, and they had been obliged to insure each NPP as a corporation in a twofold way: up to the maximum limit set by the private insurer and up to the same amount once again with the state. However, the Act left the settlement of claims exceeding the recovery limits of insurances of 50 million JPY (equivalent to 120 billion JPY as of 2011, cf. *The Asahi Shimbun*, 11 April 2012, 3) to the state – albeit depending on parliamentary decision.[12] This minimised the liability risk for NPP operators and created the socialisation of claims for damages that cannot be covered by private insurance companies. For the NPP operators it increased the necessity to steer government, parliament and bureaucracy in their interest not only with respect to the supervision of business operation and price fixing, but also in the event of an emergency (Shimura 2011, 128-66).

Government bureaucrats, electric power companies and politicians argued over who were to take the initiative in the civilian use of nuclear power, how to build and operate the first NPP, and whom to charge with the costs and risks. The solution was the founding of the Japan Atomic Power Company (*Nihon Genshiryoku Hatsuden Kabushiki Gaisha*) in 1957. Electric power companies and other private investors held 40% each, while 20% were owned by the state (Kikkawa 2004a, 301-2). The development of fast breeders (FBR) for the production of plutonium and plutonium reactors (ATR) as well as the reprocessing and uranium enrichment stayed with the Government Agency of Science and Technology. In 1957, the latter established the Nuclear Fuel Corporation (*Genshiryoku Nenryō Kōsha*), which was absorbed by the Power Reactor and Nuclear Fuel Development

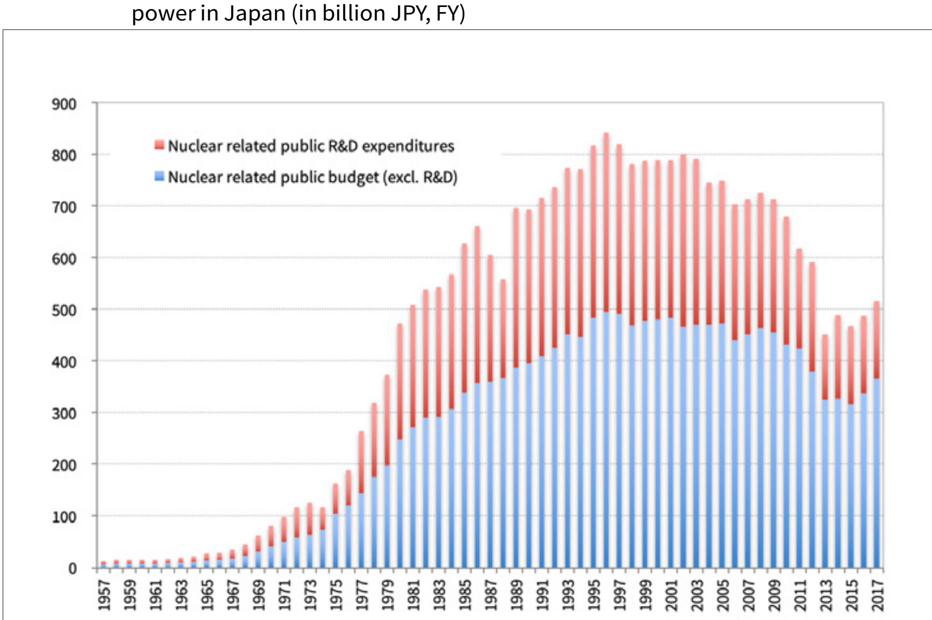
12 This final passage is seen by Takemori as a compromise between the political proponents of nuclear power generation, civil law experts and the Ministry of Finance. The latter considered it unacceptable to exempt private NPP operators from any obligation to pay compensation beyond the insurance limits and to burden public finances with such a risk of compensation. Since then, the nuclear power proponents and the NPP operators have ensured that the parliamentary decision-making process in the event of a disaster would follow their interests (Takemori 2011, 137-9).

Chart 3.6a Power generation promotion tax income in Japan (since FY 2007: 0.375 Yen/kWh, in billion JPY, FY)



Source: Author, based on MOF 2017b; AEC 2018

Chart 3.6b Released central government's budget volume for promotion and R&D of nuclear power in Japan (in billion JPY, FY)



Source: Author, based on JAIF 2018; AEC 1994, 2018; IAEA 2018a; MOF 2017b

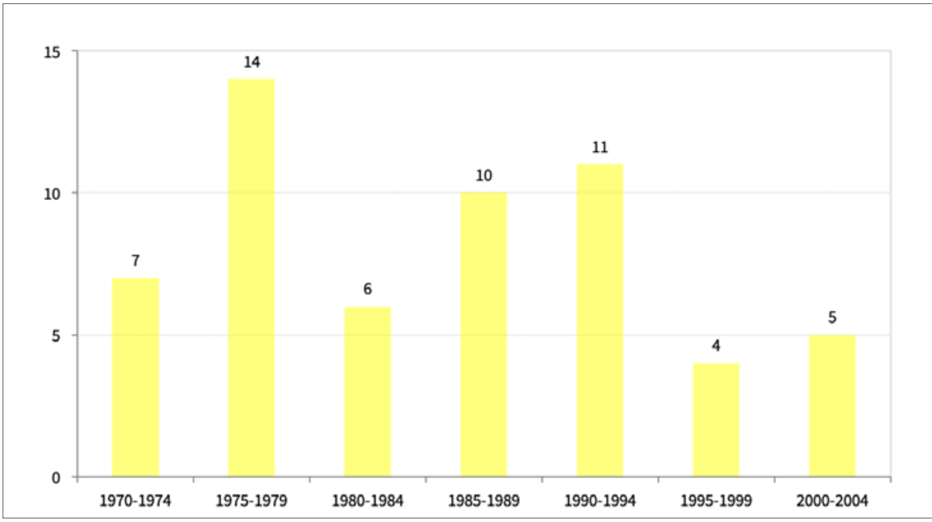
Corporation (*Dōryokuro Kakunenryō Kaihatsu Jigyōdan*) in 1967. This created a bipartite organizational structure of nuclear state activities: the METI promoted and oversaw the commercial use of nuclear power by the electric power companies, while the unprofitable activities were delegated to the Government Agency of Science and Technology (now within the Ministry of Education, Culture, Sport, Science and Technology, abbr. MEXT) (Yamaoka 2011, 90-7, 118).

Local resistance to new power plants of all kinds had been growing since the '60s. These plants produce electricity for remote metropolitan or industrial areas, but they affect people's land and fishing rights in rural areas (Yoshioka 2011a, 148). In 1974, the so-called Three Laws (*Dengen Sanpō*) were put into effect to promote and allow the construction of new power plants, especially NPPs, against local resistance and to pay high subsidies to willing communities.[13] The related budget is financed by a tax imposed on the electricity sold, included in the price and finally paid by the consumer (charts 3.6a-b).

The Electricity Act of 1964 regulates the power companies' application for the electricity price to the METI for permission. They submit their demand projection, investment and rationalisation plan and the cost accounting. The latter includes ongoing operating costs (personnel, maintenance, repair, materials, insurance, taxes) as well as fuel and capital costs (depreciation). The METI determines a rate of return on the fixed and current assets, which allows the company to continue business, that is, to pay sufficient dividends to the shareholders or interest to the lenders. The total of cost and interest on property is allocated to the types of electricity or customers and the expected demand quantities. Thus, the electricity companies are dependent on the METI insofar as the latter formally acknowledges their submitted cost and approves prices and profit margins. In other words, with the Electricity Act the state took over the risks related to damage compensation and business allocation and enabled the companies to get investment cost immediately reflected by the electricity price. Thus, costs and risks of NPPs sank to such an extent that private-sector electric power companies had no reason not to use nuclear energy commercially. Japan's first commercial NPR started operation at the NPP Tōkai in 1966.

13 According to Ōshima, 70% of these subsidies went to NPPs (Ōshima 2010, 36). In 2011, a municipality, siting a 1.35 GW NPP with a construction period of seven years and an operating period of 40 years, could receive 48.1 billion JPY in state subsidies during the decade prior to start of operation and a total of 138.4 billion JPY in state subsidies until the end (METI [2011] 2018, 3).

Chart 3.7 Number of NPRs in Japan by start of operation (ex. Tōkai and Monju, CY)



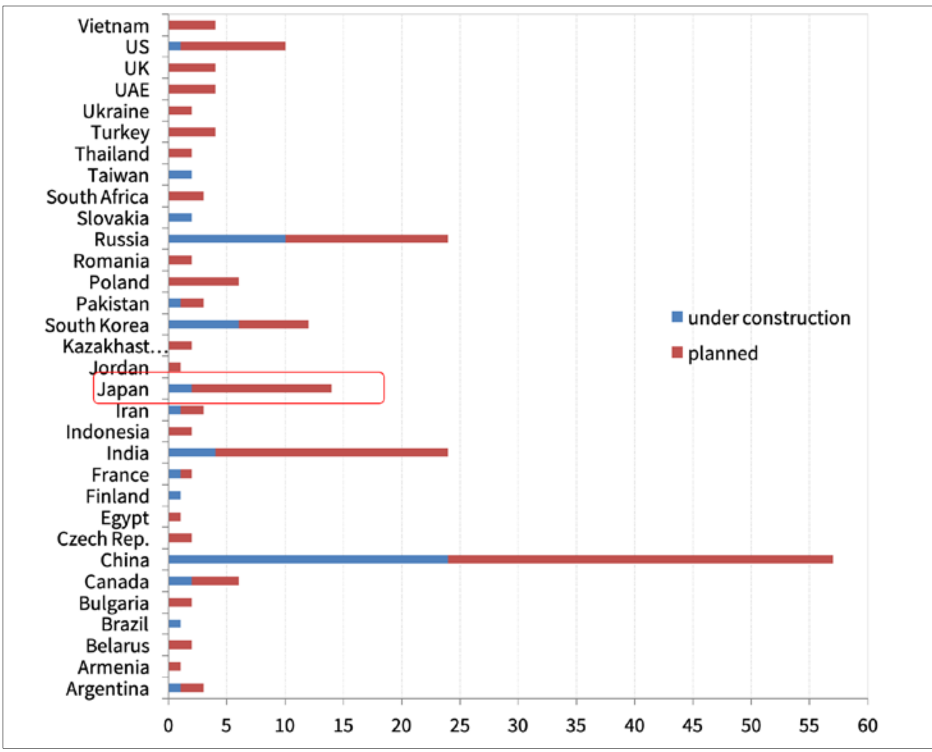
Source: Author, based on JNES 2013

In 1957, Shōriki had succeeded in importing a gas-cooled Calder Hall reactor (GCR) from the UK as research minister and vice-prime minister. The GCR was initially offered to Japan as a civilian application of military nuclear technology, able to produce weapons-grade plutonium (Yoshioka 2011c, 1292; Yamaoka 2011, 86-102). In 1960, the Japanese Atomic Power Company commissioned the construction of the reactor that started operation six years later (Yamaoka 2011, 102). At the same time, however, General Electric (GE) was commissioned the turn-key construction of a 12.5 MW boiling water reactor (BWR) for research purposes. In August 1963, it was launched with a six-month delay as the Japan Power Demonstration Reactor (JPDR), but it had to be stopped after two months due to severe malfunctions.[14] Its commissioning in October 1963 is considered to be the beginning of nuclear power generation in Japan and a shift towards the light water reactor technology promoted by the US (Yoshioka 2011c, 1297). Since 1976, GE technicians had ignored indications that the Mark-I type reactor vessel, used in addition to reactors 1-6 at the Fukushima-1 NPP in ten other reactors in Japan, is an unsuitable and extremely dangerous misconstruction for an earthquake-prone country (Tanaka 2011c, 3, 5; 2012, 106-7, 110-1).

14 The criticism of the unreliability of GE technology and its misfit to the local conditions by Japanese researchers has been defamed and suppressed as 'communist agitation' (Tateno 2011, 1288).

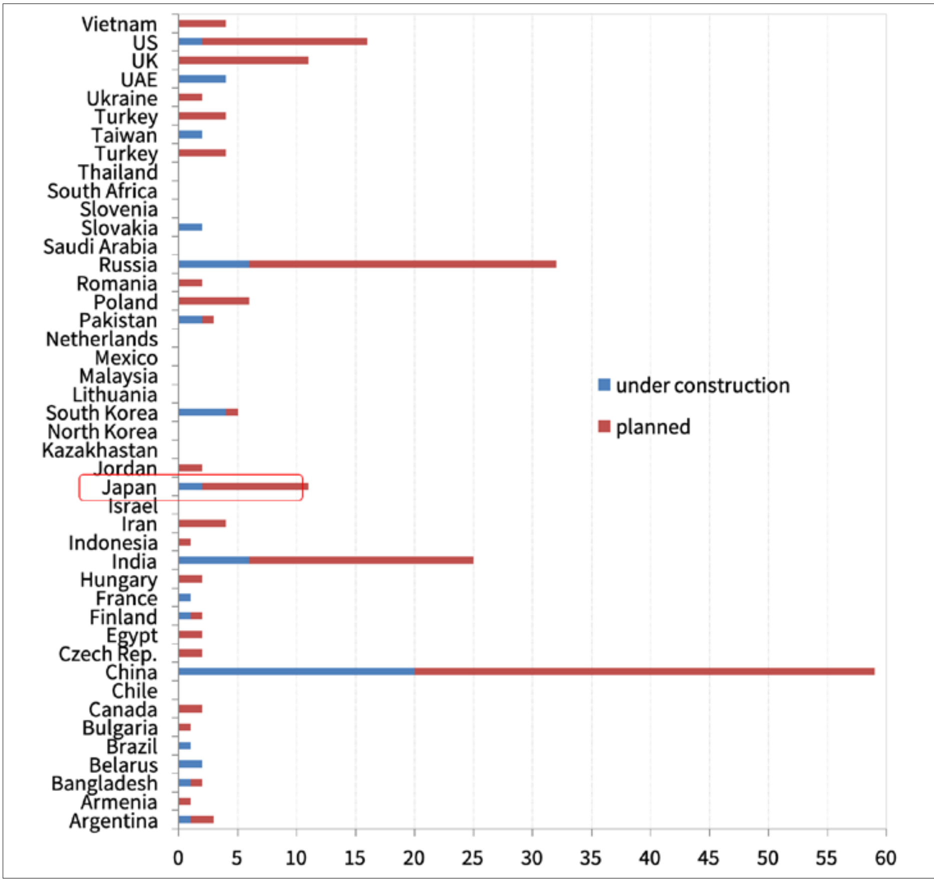
In the context of the oil crises of 1973, 1979 and 1990, averagely two new NPRs were commissioned each year. Promoted by METI, TEPCO choose the BWR developed by GE and built by GE licensees Tōshiba and Hitachi, KEPCO took Pressurized Water Boiling Reactors (PBR) developed by Westinghouse (WH) and built by its licensee Mitsubishi Heavy Industries (MHI) (Kikkawa 2004a, 303-7; Yoshioka 2011, 1297). While in the US and Western Europe NPPs were only rarely built in response to the severe catastrophes of Three Mile Island 1979, Chernobyl 1986 and Tōkaimura 1999, these disasters did not affect Japan: New NPPs were built until 2005 (charts 3.2, 3.7, 3.8a-b).

Chart 3.8a NPRs planned or under construction as of 1 July 2010 (n = 208 (59 + 149))



Source: Author, based on WNA 2018

Chart 3.8b NPRs planned or under construction as of 1 February 2018 (n = 220 (57 + 163))



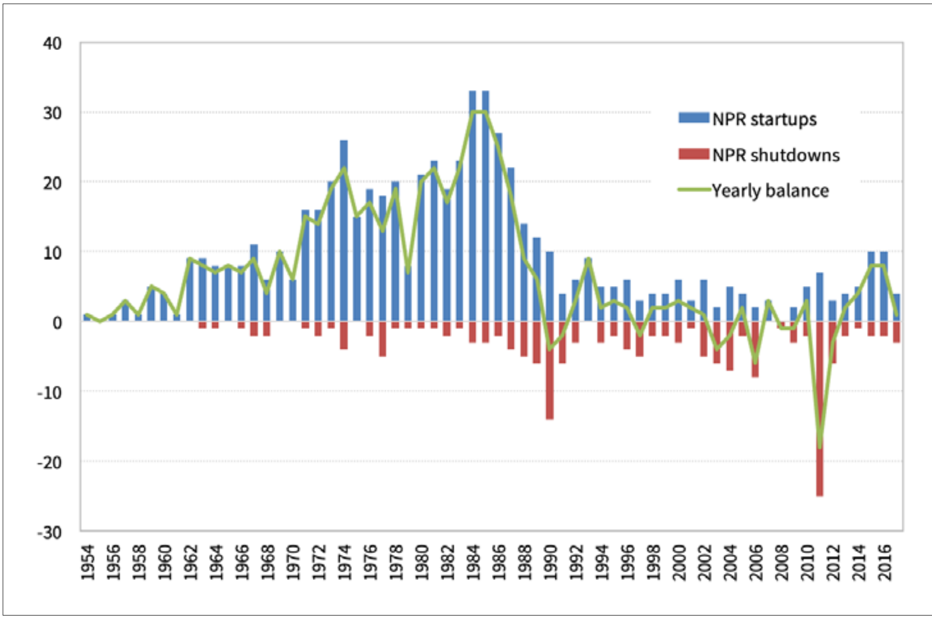
Source: Author, based on WNA 2018

3.2.3 Industrial Policy Interests: Infrastructure Export

State-political interests had paved the way for the commercial use of nuclear energy in Japan and given rise to a network called 'nuclear village' (*genshiryoku mura*), consisting of politicians, METI bureaucrats, electric power companies, NPP manufacturers or builders, construction companies, local communities, scientists and media companies (Kainuma 2011a; Īda Tetsuji 2012, 114-24). Kainuma has characterised this as 'domestic colonisation' (Kainuma 2011b, 1300-2). State policy in Japan was and is primarily economic or industrial policy. With regard to the electric power industry, the state has not only supervised, but also supported the involved companies. Ever since the ’70s, Japan’s government has focused on reducing the dependence on nuclear technology imports from the US and developing Japanese companies’ expertise in manufacturing and maintaining NPPs through an economy of scale in the domestic market up to a level, where they can eventually meet demand from overseas. Applying this pattern, the METI had guided the heavy industry in the ’60s, the automotive industry in the ’70s and the electronics industry in the ’80s. In the ’90s, however, Japan entered persistent deflation and demographic stagnation. Against this backdrop, the METI considered promoting the domestic nuclear industry and its export potential one of the last fields of influence (Takemori 2011, 56-68). For that, it was indispensable to keep the domestic use of NPPs trouble-free and at low cost, despite the site risk, serious accidents and actually high costs. With the increasing number of NPP/NPRs built in Japan in the ’70s and ’80s, the volume of orders and the share of value of Japanese NPP manufacturers or builders grew. In the late ’80s, they exported reactor pressure vessels to China together with US manufacturers (CNIC 2012b) and jointly developed a new generation of so-called Advanced Boiling Water Reactors (ABWR) for the Kashiwazaki NPP. But the nuclear catastrophes of Three Mile Island in 1979 and Chernobyl in 1986 revealed the dangers and economic risks that a private NPP/NPR operator would actually have to bear. When the US government deregulated electricity markets in the ’80s and ’90s, demand for new NPP/NPRs dropped. In Western Europe, too, the demand declined. The attempt to export NPP/NPRs to developing countries and OECD countries in the wake of the 1997 Kyōto Climate Change Agreement failed (Akaishi 2011, 156). NPP/NPR manufacturers in the US and Western Europe had to limit their business to stock maintenance and reprocessing (chart 3.9).

Meanwhile, Japan’s NPP/NPR builders were able to erect new NPPs until the first half of the 2000s. However, the partial liberalization of the Japanese electricity market and the reduction in electricity prices since the late-’90s had forced electric power companies to reduce investment in new capacity and focus on cost-effective capacity replacement. In order to obtain competencies and capacities in manufacturing, NPP/NPR builders and the METI had to open up external demand. An opportunity presented itself with the so-called Nuclear Renaissance: in response to the imminent closure of older NPPs and rising oil prices, the US government under president George Bush (2001-2009) promoted the expansion of NPP capacity as the supposedly cheapest route to reduce CO_2 emissions (Yoshioka 2011b, 15-9; Akaishi 2011, 157). The Japanese government regarded this change as highly appealing as the *Guidelines on Nuclear Policy* (*Genshiryoku seisaku taikō*, AEC 2005) and the *Plan for National Development of Nuclear Technology and Industry* (METI 2006) evince. Both aimed to secure domestic demand for NPP/NPRs and promote reprocessing of nuclear fuels (plutonium enrichment) in Japan as well as NPP/NPR exports from Japan.

Chart 3.9 Worldwide annual NPR start-ups and shutdowns

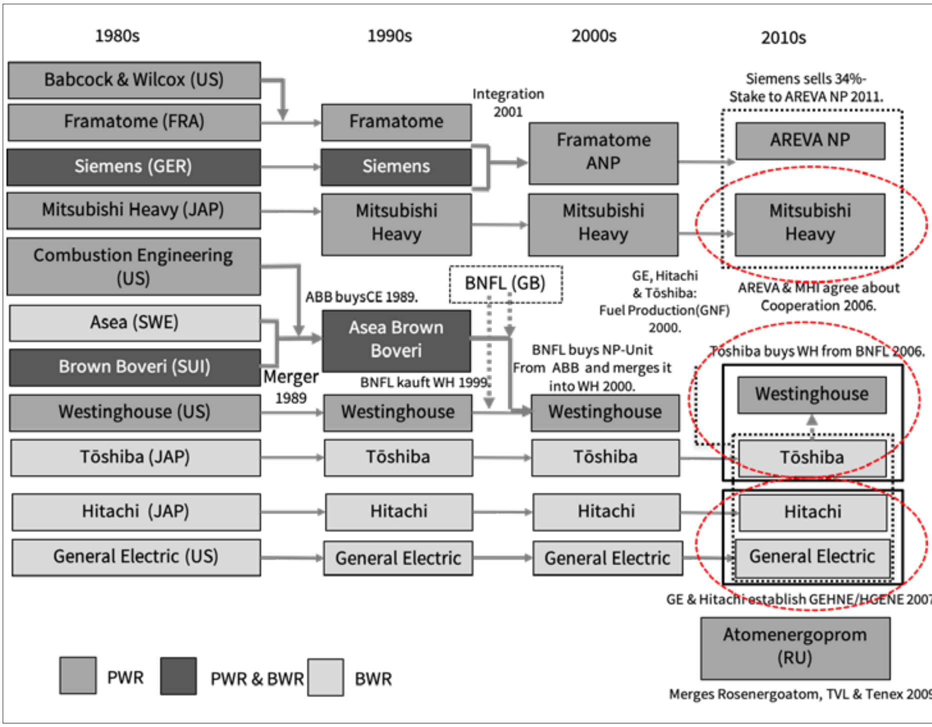


Source: Author, based on Schneider et al. 2011, 2017, 2018

Meanwhile, lacking own capabilities in building new NPP/NPRs due to the implosion of demand after 1979 and recognising the endemic risks of huge delays and cost-overruns, the US government saw its preferred partner for serving the NPP/NPR markets of the US, Asia, the Middle East and Eastern Europe in Japan and its NPP/NPR manufacturers (Akaishi 2011, 158). For their part, METI and Japanese NPP/NPR manufacturers considered the US the ideal partner for eliminating all foreign and security policy obstacles – notwithstanding the ultimate guarantee of Japan's right to operate NPP/NPRs and process nuclear fuel.

In 2006, Tōshiba acquired a 77% majority stake into Westinghouse (WH) from BNFL for 5.4 billion USD or 640 billion JPY, which was about three times as much as the initial estimations among insiders and more than double the competing offer made by Mitsubishi Heavy Industries (MHI). Later, Tōshiba took over another 10% of WH shares. Meanwhile, MHI began a cooperation with French AREVA. A year later, Hitachi and GE merged their NPP manufacturing businesses. Supported by the METI with subsidies, insurances and loan guarantees, Japan's NPP/NPR manufacturers decided to enter the global market (chart 3.10, fig. 3.2).

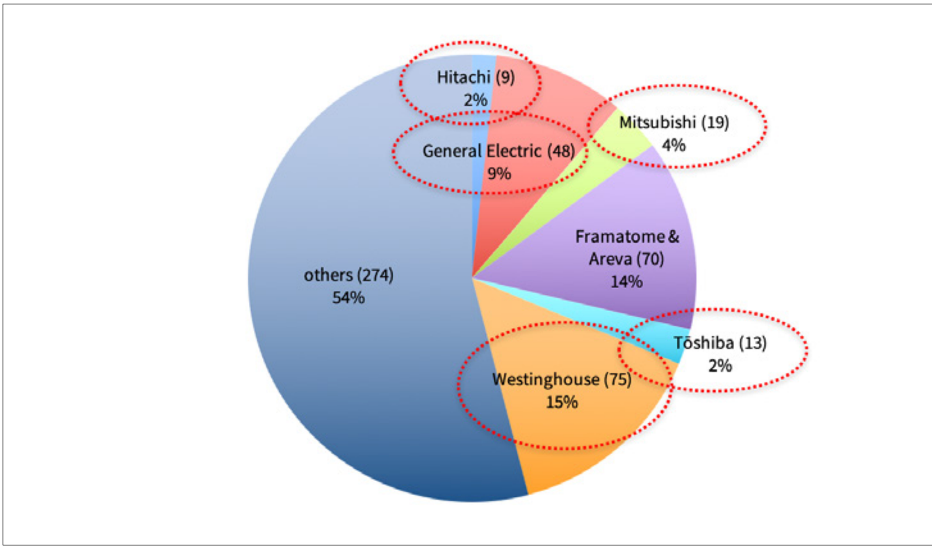
Figure 3.2 Concentration of ownership in the global NPP/NPR building industry



Source: Author, based on AEC 2017, 255

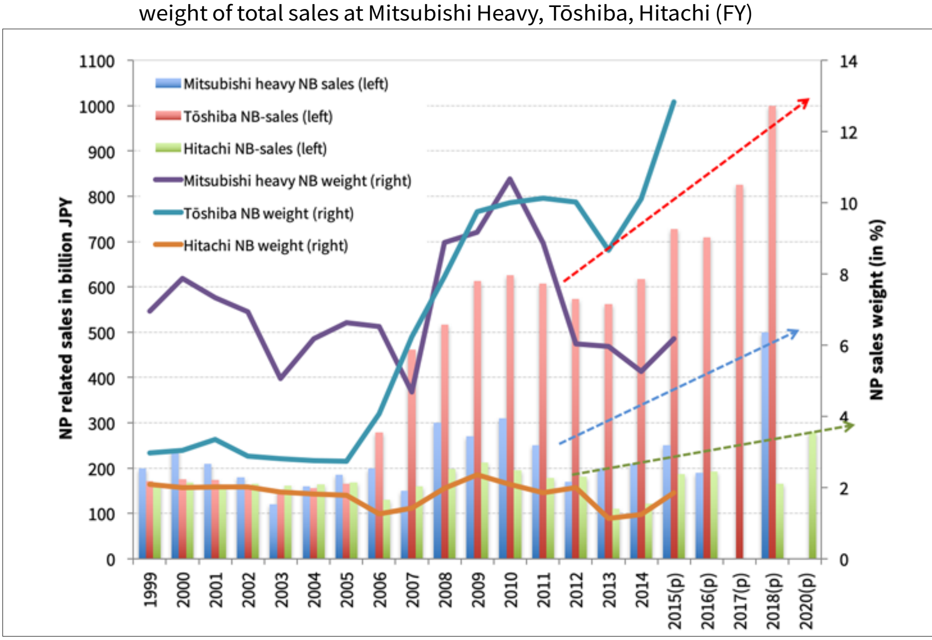
But these manufacturers are diversified conglomerates, in whose portfolio the NPP/NPR business is only one part. Thus, NPP/NPR exports were considered promisingly profitable even after 2011 insofar as they were insured and subsidised, that is, made less risky by Japan's government at the expense of the taxpayer (CCNE 2017, 264-5) (charts 3.11a-b).

Chart 3.10 NPRs in operation or under construction by plant builder (worldwide n = 507, as of 2017/12/31, in brackets: no. of reactors)



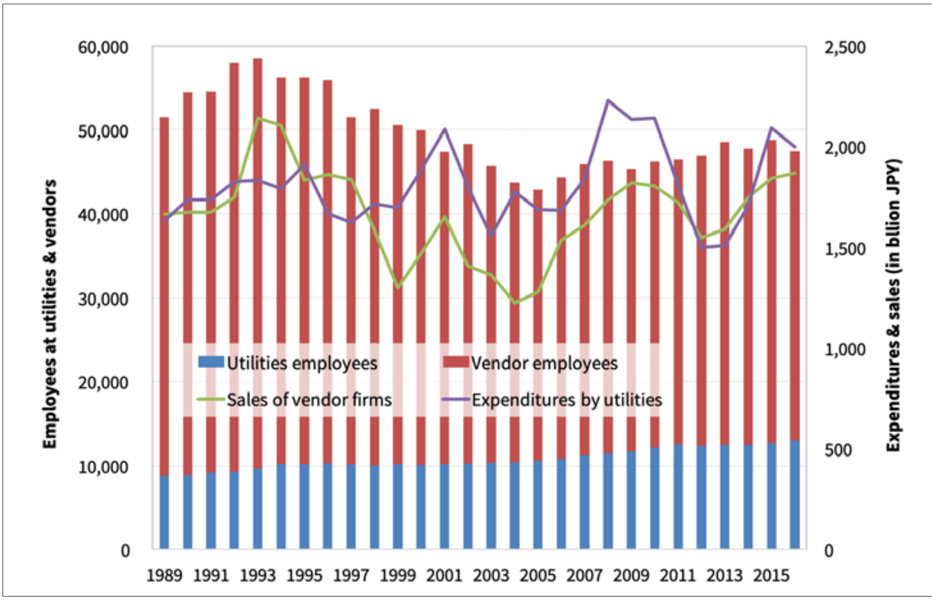
Source: Author, based on IAEA 2018b

Chart 3.11a Estimation of nuclear power plant business sales and weight of total sales at Mitsubishi Heavy, Tōshiba, Hitachi (FY)



Source: Author, based on investors relation (IR)-reports

Chart 3.11b Nuclear power related expenditures of utilities, sales of vendors and employees of utilities and vendors in Japan (FY)



Source: Author, based on JAIF 2017

Even on paper (that is, in the planning phase) building and exporting NPP/NPRs is not feasible as private business without comprehensive state support and monopolistic or oligopolistic electric power companies as final client and NPP/NPR operator. In order to bundle export activities nationally, especially towards Vietnam, METI, the nine electric power companies and the three NPP/NPR builders founded the International Atomic Energy Development Corporation (JINED) at the end of 2010. But prospects deteriorated due to the Fukushima nuclear disaster of March 2011: new orders for NPP/NPRs were held off. Whether domestically or abroad, almost all new NPP/NPR building projects have seen huge delays and cost overruns. Despite intense political, financial and diplomatic support by Japan's government, Japanese export projects have been cancelled in Vietnam, Taiwan, the US, suspended in Lithuania, delayed in India (Suzuki 2017, 90-3; CCNE 2017, 251-60) or will be in Turkey (*Tōkyō Shimbun Online*, 16 March 2018).

Facing a series of troubles, decreasing profitability and piling compensation demands from WH clients, Tōshiba manipulated its financial accounting to avoid huge impairments on its WH-related goodwill to an amount, that exceeded its equity capital. Based on optimistic expectations for sales and profits[15] the goodwill was accounted as asset value, reflecting the gap between the investment of more than 6.1 billion USD paid by Tōshiba to acquire and control WH and the book value of WH net assets (estimated at 1.7 billion USD). Impairments became necessary, as the profitability of WH's business and its net assets deteriorated and the gap between expected and actual earnings widened. Even after first impairments of 2.4 billion USD in FY2015, further impairments were estimated to account for more than 3 billion USD in FY2016 against equity capital of 2.7 billion USD in FY2015. Ultimately, as the problems at WH could not be solved, Tōshiba's critical financial state surfaced. Thus, Tōshiba decided to let its subsidiary WH go bankrupt in March 2017. But it had to pay WH-related guarantees of 5.8 billion USD, mainly to WH clients. As a consequence, the risk of losses exceeding equity capital became evident in March 2017. Tōshiba had to indicate a negative equity capital of about minus 5 billion USD. In order to secure sufficient cash flow and avoid its own bankruptcy, Tōshiba sold most of its profitable businesses (e.g. medical equipment manufacturing for 6 billion USD to Canon in 2016, flash memory manufacturing for estimated 15 billion USD to Pangea in FY2017) and all its financial claims of 8.1 billion USD against WH for 2.1 billion USD to Nucleus. Finally, it had to raise new equity capital of 5.4 billion USD (by issuing 2.3 billion new shares in addition to existing 4.2 billion shares) in late 2017. Thus, the total WH-related losses for Tōshiba amounted to more than 12 billion USD (cf. FACTA 2017; Matsumura 2017; Tōshiba 2018).

Although domestic taxpayers and electricity consumers are charged with the financial burdens caused by NPP exports under the guidance of the Japanese state, this business itself inheres a level of exposure to political, financial and technological risks, that exceeds the controlling abilities of the alliance between state, builders and operators.

15 Before the decision to exit the WH-related NPP/NPR building business (outside Japan) in 2017, Tōshiba assumed for its business planning in November 2015 that there were more than 400 NPRs planned worldwide, of which Tōshiba aimed at receiving 64 (Tōshiba 2018).

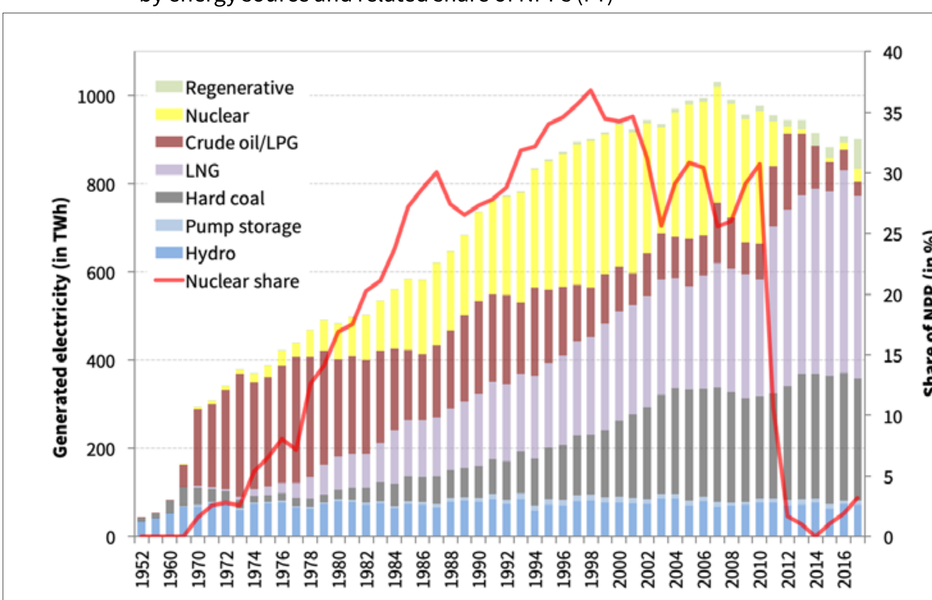
3.3 Fundamental Problems of a NPP-Centred Electricity Industry

By the end of the ’90s, the share of electricity, generated at NPPs in Japan, increased to one third (charts 3.12a-b), while NPPs accounted for one fifth of the installed capacity of commercial electricity generation (charts 3.5a-b).

3.3.1 Inflexible and Costly Control of Power Supply

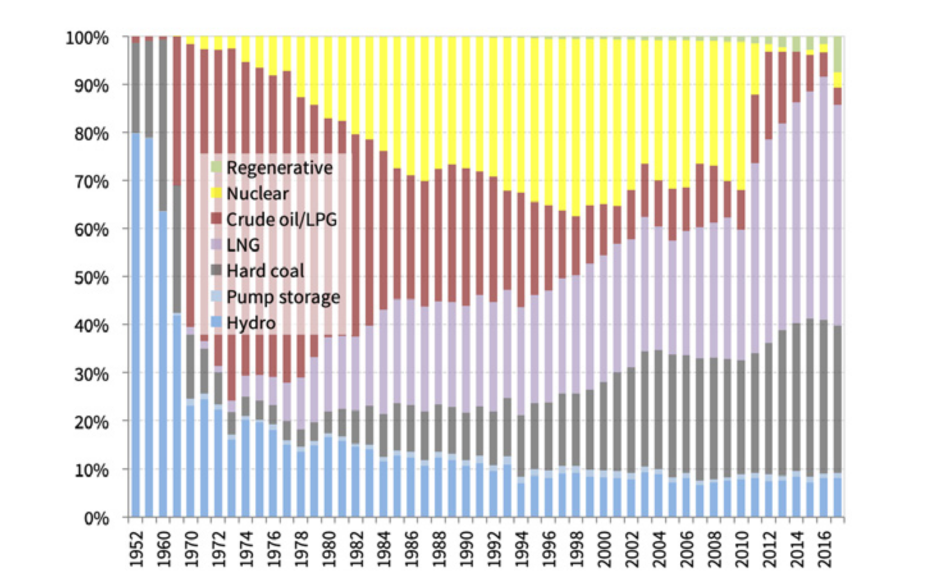
Compared to fossil fuel fired thermal powers plants, the construction costs of NPPs are high, in both absolute and relative terms (see § 3.3.3). Starting and stopping NPPs is expensive and time-consuming. Consequently, NPPs have to run continuously. They are therefore used to cover the baseload. The higher the share of NPPs in the electric power production, the greater the production surplus or oversupply that accumulates during night-time under-load phases, when demand for electricity is low. Costly hydro-pumped storage plants are used to absorb and accumulate the surplus and release it to the grid at peak-load time, when demand for electricity is higher than the continuously available supply, or baseload (fig. 3.3).

Chart 3.12a Annual commercial electricity generation (ex. in-house, including FIT) in Japan by energy source and related share of NPPs (FY)



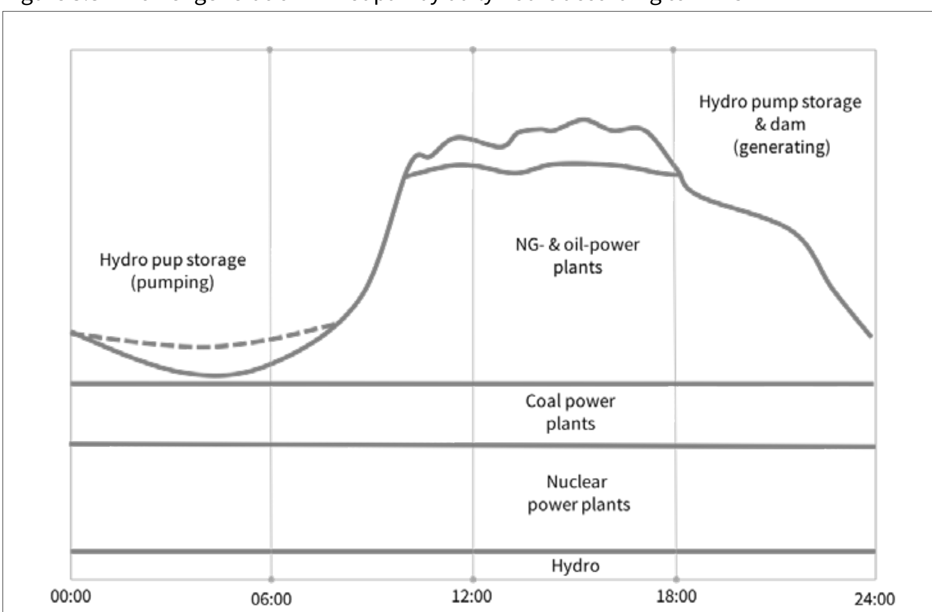
Source: Author, based on METI 2018c; FEPC 2018

Chart 3.12b Composition of commercial electricity generation in Japan by energy source (excluding in-house, including FIT, FY)



Source: Author, based on METI 2018c; FEPC 2018

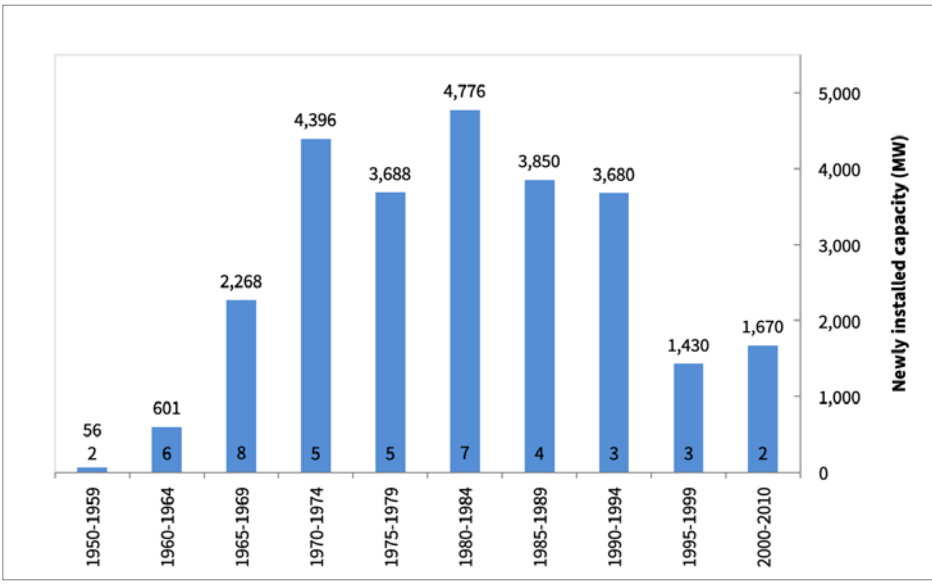
Figure 3.3 Power generation mix Japan by daily hours according to FEPC



Source: Author, based on FEPC 2011

Between 1950 and 2010 hydro-pumped storage power plants with a total generating capacity of 26.4 GW had been installed in Japan (chart 3.13). As of the end of March 2017, METI electricity statistics indicated an installed capacity of even 27.5 GW, at 10% of the total capacity (chart 3.5a). But, actually, these power plants have generated 7.6 TWh or less than 0.85% of all generated electricity in Japan, which means that their utilization rate is less than 3.2%. This explains partly why this type of electricity is extremely expensive.

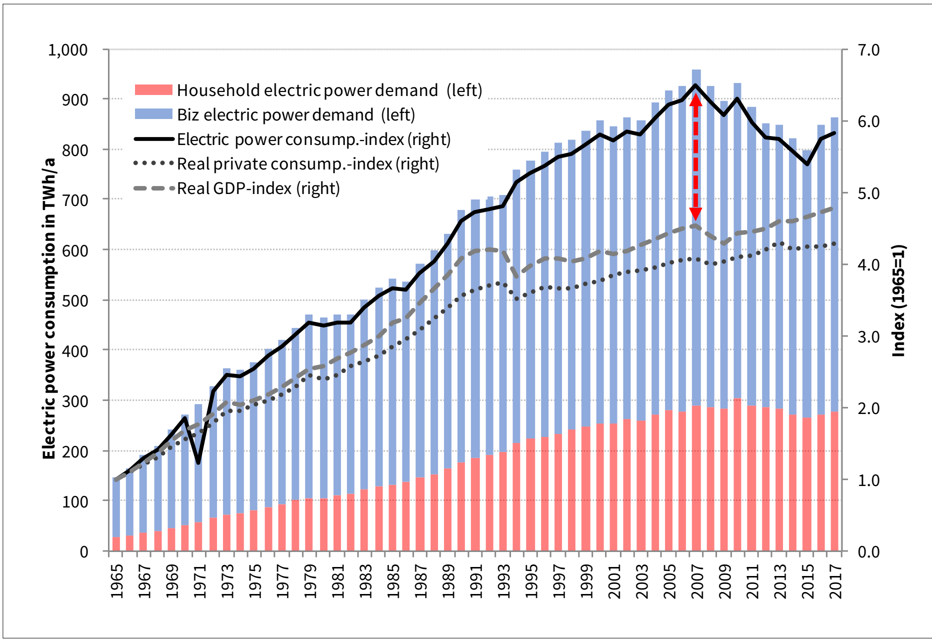
Chart 3.13 Newly installed capacity and number of hydro-pumped storage plants in Japan by start of operation (CY)



Source: Author, based on JEPOC 2018

However, about 25-35% of the injected electricity is lost during the double-step transformation process. Even with a relatively high single transformation efficiency of estimated 80-85% for each step (pumping and generating), the total energy loss ends up a little bit higher at 28-36%. In addition to high installation cost, low utilization rate and transformation losses, the different generation cost between hydro-pumped storage power plants and oil-fired thermal power plants, otherwise used to cover the peak load, must be considered: 0.70-0.96 JPY/kWh that is to be added to the cost of NPP-generated electricity.[16] The same applies to the longer electric power lines and additional grid facilities connecting the NPPs with the main electricity consumers. NPPs are built far away from the industrial-urban agglomerations where the demand for electric power is high.

Chart 3.14 Electric power consumption in Japan (excluding self-production)



Source: Author, based on JBHI 2018; METI 2018b, 2018c; CAO 2018a

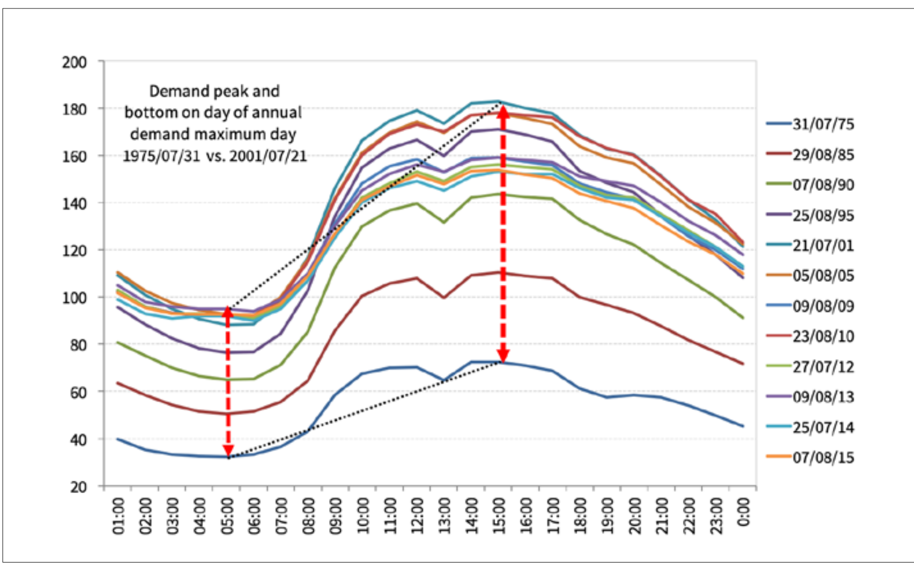
As distinct from standard textbooks assuming a free market economy where supply follows demand, Japan's electric power industry and the dissemination of NPPs exemplify the reality of an oligopolistic economy: since the rapid expansion of NPP capacity in the '70s, electric power consumption in Japan has been boosted faster than real private consumption

16 For the period from 1970 to 2010, Ōshima (2011c, 112) calculates the producer costs (excluding subsidies) for hydro-pumped storage power plants at 52.04 JPY/kWh (42.79 JPY/kWh for 2000-2007) and 9.87 JPY/kWh for thermal power plants. Akimoto (2011, 16) estimates the costs (2005-2007) for oil-fired thermal power plants at 13.8-23.2 JPY/kWh. The cost difference between hydro-pumped storage and oil-fired thermal power plants is thus 28.84-38.24 JPY/kWh (simple average of 33.54 JPY/kWh for 1970-2010) or 19.59-28.99 JPY/kWh (simple average of 24.29 JPY/kWh for 2005-2007). With 8.74 TWh, generated in hydro-pumped storage plants in 2010, the difference in electricity costs between hydro-pumped storage plants and oil-fired thermal power plants amounted to a total of 212.3-293.1 billion JPY in 2010.

and real GDP (chart 3.14). In other words, supply leads demand, because it becomes critical to increase utilization and fuel demand once expensive and inflexible capacity is installed, and even more so if the installation is heavily subsidised by the state and capital cost can be shifted to consumers as part of the regulated electricity retail price, as was the case until 2016 (see § 3.3.4).

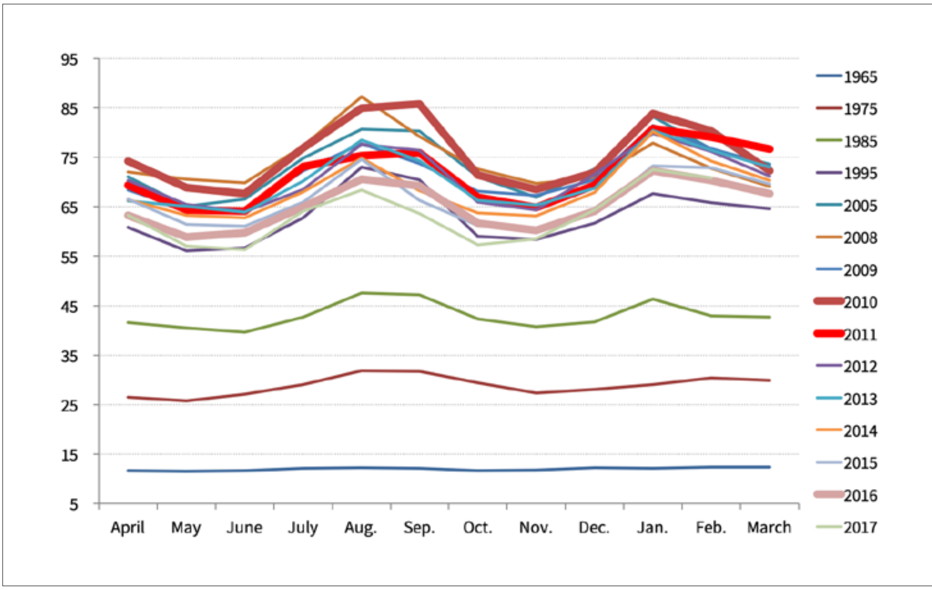
But since the early ’90s Japan’s economy has been struggling with deflationary stagnation, relocation of industrial capacity abroad and demographic contraction. Under such conditions, the baseload cannot be increased permanently. The electricity companies managed to stimulate electricity consumption with relatively low electricity prices for large corporations and full electrification campaigns for private households until 2007-2008, but this did not elevate the baseload. Rather, seasonal and daily peak loads increased and widened the difference between peak and baseload (charts 3.15a-b).

Chart 3.15a Capacity peaks by maximum day and hours in Japan (regional monopolies/ FEPC, GW)



Source: Author, based on FEPC 2018; METI 2018b, 2018c

Chart 3.15b Sold electric power by month in Japan (regional monopolies/FEPC, in TWh, FY)



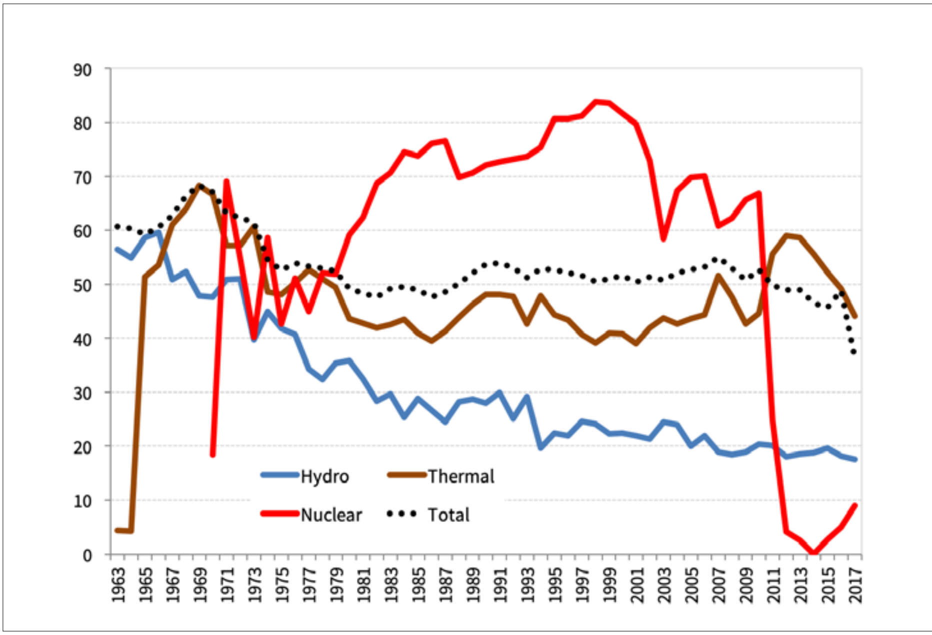
Source: Author, based on based on FEPC 2018; METI 2018b, 2018c

The widening gap between peak and baseload and the large fluctuations in the production and consumption of electricity caused the utilization rate of the entire power plant fleet first to fall and then to stagnate at a low level. This was due to the increased share of NPPs in electricity production and the decreased utilization of hydropower and thermal power plants. In addition, it is noteworthy that the utilization rate of NPPs had been inclined to fall since FY1999, when it reached 84% (chart 3.16). Back then, the total capacity of NPPs amounted to 45 GW. Entering a period of increased seismic activity and aging NPPs, there were more and more accidents and defects that the electric power companies tried to cover up.[17] The low utilization of hydropower and thermal power plants shows

17 In July 2000, a former GE technician who had been commissioned by TEPCO to inspect 13 NPRs at the NPPs of Kashiwazaki and Fukushima-1 and -2 informed METI that TEPCO had hidden cracks in the reactor walls, improper wiring and repair breakdowns. TEPCO denied the allegations, while METI delayed the investigation for more than two years and also released the informant's name to TEPCO. However, in September 2002, after GE had issued official evidence as a nuclear power plant producer on a METI request in November 2001 and after an internal investigation in March 2002 it was publicly conceded that TEPCO had falsified or withheld information related to the self-assessing of 13 NPRs since the '80s, i.e. over a 29 year period (Yoshioka 2011a, 321-5). In April 2003, all TEPCO reactors underwent a special review and were disconnected (*The Asahi Shimbun*, 15 April 2003, 1).

that – contrary to the threats by companies and government that electric power shortages or outages will occur if NPPs are shut down – there are sufficient capacities for non-nuclear electricity generation to compensate for a nuclear phase-out (Uezono 2012, 48-51).

Chart 3.16 Utilization rate of electric power generating capacity by source of energy in Japan (regional monopolies/FEPC, vs. 8760 h/a in %, FY)



Source: Author, based on FEPC 2018; METI 2018b, 2018c

Peak loads could be reduced by introducing tariffs that reward peak power savings. But in reality over-consumption is stimulated by tariffs that lower the price of electricity per unit in the base price category when the total consumption increases. This applies to corporate customers, who consume about 70% of Japan's total electricity (chart 3.14) and probably more during the annual peak days in summer and winter (fig. 3.3, charts 3.15a-b). Thus, large industrial customers, who want to reduce their unit costs, are pushed to fully exploit the consumption volume allowed by the basic price band, especially in periods of high consumption (Yū Tanaka 2011, 138-9). The cost of building and maintaining power generation capacity

In July 2007, all seven reactors of the Kashiwazaki NPP were severely damaged during the Niigata earthquake (Yoshioka 2011b, 36-7).

is included in the retail price of electricity through depreciation costs and the return on operating assets, recognised by the METI and paid for by private households. Thus, the power companies are not encouraged to be efficient, that is, to install and maintain only those capacities that they can control flexibly and use efficiently. Normally, efforts should be undertaken to reduce peak load demand. It would also be conceivable to draw on surplus electricity from other parts of Japan (in summer from northern, in winter from southern Japan) instead of constantly maintaining own extra peak-load capacity. However, the AC frequencies in Japan differ between East (50 Hz) and West (60 Hz). One would have to (a) adjust the frequencies, (b) switch over to DC grids or (c) expand the transformation capacity, which is currently limited to 1.2 GW. All three alternatives are rejected by the electricity companies with reference to unreasonably high costs. In actual fact, they mean to avoid competing against each other and lowering entry barriers for new competitors.

3.3.2 Nuclear Fuel Cycle Unclosed

3.3.2.a Front-End: Expensive and Limited Uranium Enrichment

To operate NPPs, nuclear fuel must be enriched, i.e., the proportion of easily fissile uranium 235 must be increased from only 0.7% in natural uranium. For this, uranium ore is mined, pulverised to yellow cake (U3O8) with a uranium concentration of 84.8% and then converted to uranium hexafluoride (UF6). A centrifuge separates UF6 into a depleted fraction and an enriched fraction. The latter is converted into uranium dioxide (UOX) and processed into uranium tablets (d = 1 cm, h = 1 cm, g = 5-8 g) and fuel rods (h = 4 m, w = 20 cm), 95-97% of which consist of uranium 238 and 3-5% of uranium 235. In a PWR 51,000 fuel rods with 87.0 t UOX are used, in a BWR 48,000 fuel rods with 88.6 t UOX (1,000 MW output) (NFI). One third of these fuel rods must be replaced annually.

For a long time, Japan had obtained enriched uranium almost exclusively from the US (Suzuki 2006, 195). At the beginning of the ’80s, a state-owned company under the umbrella of the State Science Agency commissioned the first small enrichment plant. Afterwards, however, these activities were transferred to the electric power companies, while the State Science Agency (as part of the Ministry for Culture and Education, today’s MEXT) focused on reactor research (Yoshioka 2011a, 179-80). Confronted with the consequences of operating NPPs since the ’70s (growing fuel requirements and accumulation of radioactive residues) and stimulated by the change from the restrictive anti-proliferation course of the US government under Jimmy Carter to nuclear tolerance under Ronald Reagan (in 1981), METI and the electric power companies began to establish their own capacities for front-end and back-end: Rokkashomura (Aomori Prefecture) was to become the site for Japanese uranium enrichment, reprocessing and interim storage of nuclear fuels. Between 1988 and 1992, Japan Nuclear Fuel Ltd (JNFL, *Nihon Gennen Sangyō Kabushiki Gaisha*), founded by the NPP operators in 1985, invested 250 billion JPY in the construction of a plant where uranium has been enriched since then. The plant consists of seven cascades with several hundred gas centrifuges each. The lifespan of a cascade is approximately ten years. In 2010, JNFL announced its intention to bring five of the seven cascades with an annual capacity of 1,500 t of uranium separation work (UTA) into operation by 2015 and ten cascades by 2020 (JNFL). In actuality, only one cascade (150 t UTA/year) was in operation by 2010. This one cascade in operation was supposed to produce the 30 t uranium fuel rods (UO) needed for the annual consumption of a 1.0 GW NPR (Yoshioka 2011b, 39; Koide 2011a, 115). Since December 2010, the only operating cascade has also been at a standstill. Japan's NPP operators had to turn again to foreign countries, mainly Canada and Australia, to obtain almost all of their enriched uranium (Yoshioka 2011a, 345).

But what are the usual costs for producing uranium fuel (UOX)? First, the material process of uranium enrichment must be considered: 110,000 t uranium ore yield 250 t uranium (U_3O_8) and 310 t UF_6. From 116 t UTA, 40 t enriched UF_6 (3.5% uranium 235 concentration) are extracted, and finally 30 t uranium oxide (UOX) are produced (fig. 3.4).

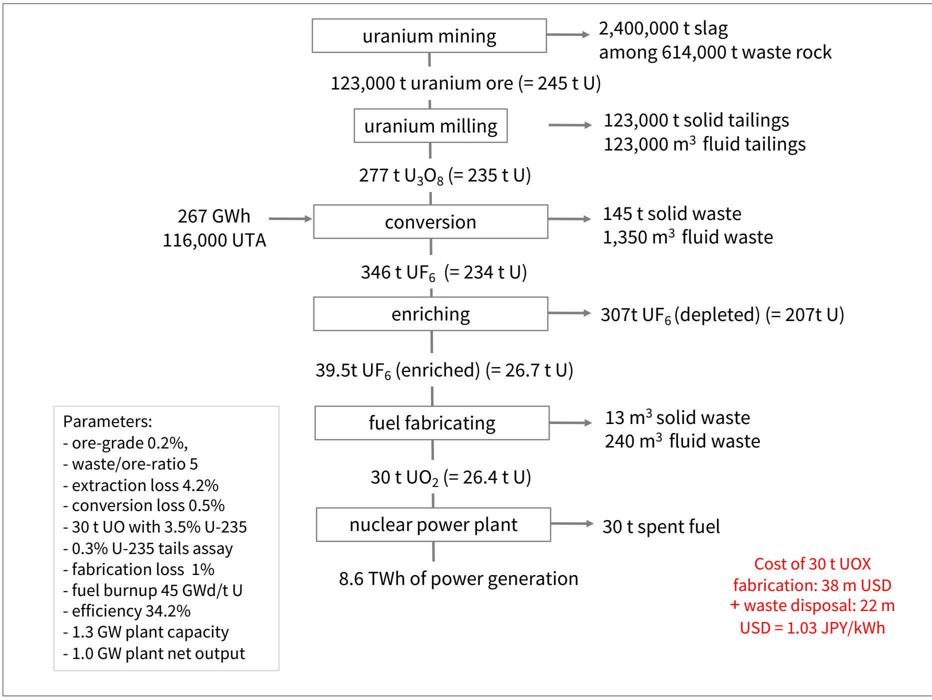
The market price for uranium was 22 USD/kg in 2002, rose to 300 USD/kg in 2007 and stood at 115 USD/kg at the end of 2011. In February 2018, the market price for uranium marked 47 USD/kg (UxC 2018). The market price for enrichment (UTA) rose from 90 USD/kg UTA in 1995 to 162 USD/kg in 2009 and stood at 140 USD/kg at the end of 2011. By February 2018 it had fallen to 37 USD/kg (UCX 2018). Conversion to and from UF_6 cost 8.50 USD/kg at the end of 2011; in February 2018 6.25 USD/kg U_3O_8 and the final production 460 USD/kg U. As of March 2018 the cost of producing 30 t of nuclear fuel (UOX) amounted to 37.8 million USD (2011: 58.4 million USD)[18] plus the cost of 22.2 million USD (2011: 29.5 million USD) for the disposal of 187 t of depleted uranium and 30 t of spent UOX fuel rods.[19] It goes without saying that this process consumes energy, the generation of which results in the emission of CO_2.[20] If the total front-end cost of 38-60 million USD or 4.0-6.3 billion JPY at 105 JPY/USD (in 2011: 58-88

18 17.9 million USD for U_3O_8 (Natural Uranium) + 1.35 million USD for Conversion + 6.35 million USD for Enrichment + 12.2 million USD for Fuel Fabrication = 37.8 million USD in total.

19 Author's calculation based on WISE Uranium Project 2009a.

20 For the production of 30 t UOX (at a 0.2% uranium ore concentration in the open mining and use of electricity from coal-fired power plants) 55,000 t carbon dioxide are emitted (calculation based on WISE Uranium Project 2009b).

Figure 3.4 Material processing in nuclear fuel production (front-end)



Source: Author, based on Koide 2011a, 115; WISE Uranium Project 2009a, 2009b; OECD 1994, 10-6

million US or 4.6-7.0 billion JPY at 77 JPY/USD) is added to the amount of electricity generated by a 1.0 GW NPR at an annual capacity utilization of 70% (6.132 TWh), the front-end cost is 0.65-1.03 JPY/kWh (in 2011: 0.76-1.15 JPY/kWh). However, the cost of uranium enriched in Japan is several times higher than the international market prices due to high import prices, long transport routes, low economies of scale and highly vulnerable enrichment plants (Yoshioka 2011a, 354; 2011b, 40). Fuel rods and fuel modules have been manufactured in Japan since 1971 – by Japan Nuclear Fuel, a joint venture (JV) of GE, Tōshiba and Hitachi (since 2001 a GNF-J and GE subsidiary), by Mitsubishi Nuclear Fuel Co., Ltd. (JV of Mitsubishi Heavy, Mitsubishi Corporation and AREVA) and Nuclear Fuel Industries (JV of Westinghouse, Sumitomo and Furukawa Electric).

The problematic state of domestic uranium enrichment has not been prioritized in Japan as the government has given the import and enrichment of uranium a subordinate role in its nuclear policy. The aim was to maintain this variant as a second option and entitlement. The primary goal has always been the production of home-made plutonium to reduce Japan's dependency on foreign countries and keep the foreign policy option of owning nuclear weapons open.

3.3.2.b Back-End: Dangerous and Expensive Plutonium Cycle and Unresolved Storage

After a period of 36-48 months, fission products accumulate in the fuel rods and so their reactivity decreases;[21] about one third of the 90 t of fuel (per NPR with a capacity of 1 GW) has to be replaced annually (Strohm 2011, 153). At the time of removal, the fuel rods consist of 93-95% uranium 238, 1% each of uranium 235 and plutonium 239[22] and 3-5% of nuclear fission products. Fuel rods are initially put into so-called spent fuel cooling pools, then stored at interim or permanent disposal sites or reprocessed. Reprocessing is aimed at recovering plutonium and uranium by separating them chemically first from the fission products and then from each other. Uranium can be re-used for the production of uranium (UOX) fuel rods,[23] while most of the plutonium (civil use assumed) can be processed with uranium 238 to form mixed oxide (MOX) fuel rods consisting of uranium and plutonium dioxide (fig. 3.5).

At each stage of the process, radioactive particles (e.g. caesium, krypton, xenon, tritium) remain. Large quantities of contaminated residues are produced, which often escape into the environment (Strohm 2011, 639-46; Suzuki 2006, 81-96). MOX fuels were supposed to be used in so-called fast breeders (FBR). There, fast neutrons are first generated with plutonium 239. Uranium 238 absorbs these neutrons and transforms them, too, into plutonium 239, which is supposed to produce more plutonium 239 in addition to electricity that has to be used. The MOX fuels contain 20-30% fissile plutonium (Pu_f).[24] So far, however, all FBR programmes worldwide

21 Among more than 200 isotopes these are, for example, caesium, technetium, krypton, strontium, iodine, ruthenium and rhodium (Strohm 2011, 154; Hirose 2010, 205; Kamisawa 2011a, 76).

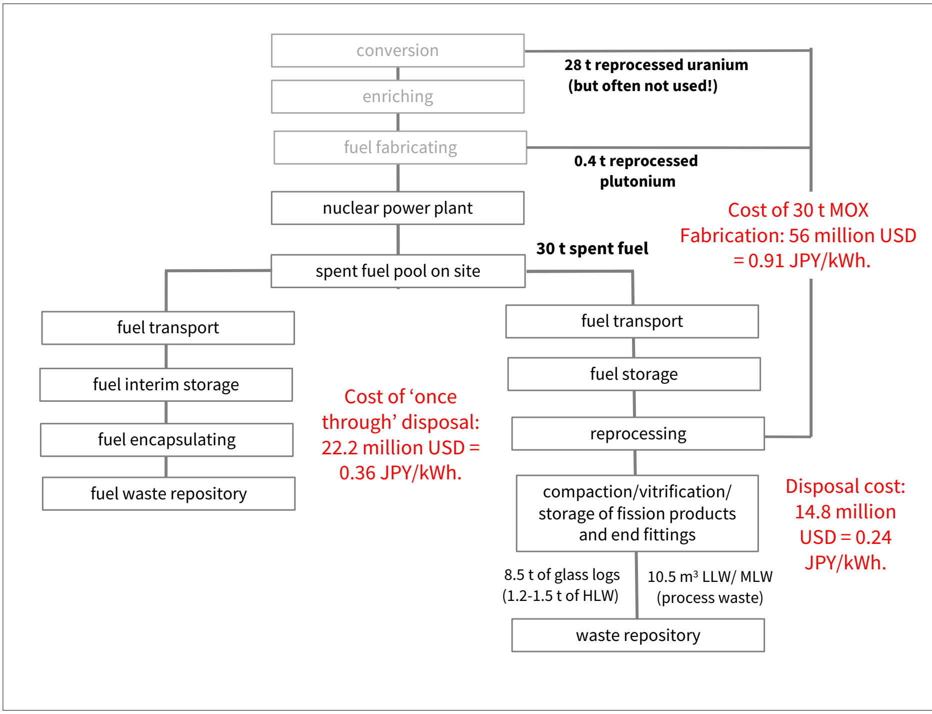
22 Plutonium 239 is formed when uranium absorbs 238 neutrons and transforms into plutonium 239 via uranium 239 and neptunium 239 (Hirose 2010, 250).

23 In fact, this rarely happened because natural uranium had been significantly cheaper than the uranium produced during processing for a long time (Bunn et al. 2003, 3-4). As of February 2018, this price/cost difference still exists, but has shrunken along with the price for reprocessed uranium of 57 USD/kg UTA vs. 47 USD/kg for natural uranium (U_3O_8).

24 Bunn et al. 2003, 82; Takubo 2011, 174; Hirose 2010, 250-2; Strohm 2011, 164.

have failed and been discontinued, except in Russia, India and Japan.[25] MOX fuels are now typically used in Light Water Reactors (LWR) with a PU_f concentration of 4-9%.

Figure 3.5 Disposal/reprocessing of (spent) nuclear fuel (back-end)



Source: Author, based on OECD 1994, 16; MIT 2003, 121; WISE Uranium Project 2009a, 2009b

25 "After spending more than 1 trillion JPY (9 billion USD) on its Monju prototype fast-neutron breeder, Japan's government finally decided to decommission it entirely in December 2016. Even though the facility had operated only 250 days during its 22-year existence, government ministers still declared that the official policy of developing a fast reactor 'has not changed at all' – and even announced a plan to draw up a 'strategic roadmap' for fast-reactor development by 2018. The current idea is for Japan to join, as a junior partner, the French programme to design and build a fast reactor called the Advanced Sodium Technological Reactor for Industrial Demonstration on French soil" (Takubo 2017, 182-3).

How much does it cost to produce MOX fuel?[26] If one MOX fuel load for an LWR is to be manufactured as equivalent of 30 t uranium oxide (UOX), 30 t MOX with a PU_f-concentration of 4.25% result from combining 1.7 t plutonium or Pu (= 1.1 t PU_f) and enriched 24.9 t uranium (= 28.2 t UO_2). To extract 1.7 t of Pu, normally reprocessing of about 180 t of spent fuel (UO_3) is required.[27] In addition to the 1.7 t PU (at a currently estimated cost of 3,300 USD/kg PU), 150 t of uranium reprocessed are to be extracted, 25 t of which are required for MOX production (at currently estimated cost of 57 USD/kg). The remaining 125 t of uranium worth 7 million USD (57 USD/kg) can be used for uranium enrichment. 49 million USD have to be added as cost of fabricating 30 t MOX fuel (WISE Uranium Project 2016-2018: 1,840 USD/kg HM). Thus, the cost of producing 30 t MOX fuel out of spent fuel would currently amount to about 49 million USD.[28] This is almost 70% more expensive than the 'once through' or open cycle of enriching natural uranium and manufacturing UOX fuel rods (29 million USD) (WISE Uranium Project 2009c). If the cost savings are set off against the spent fuel disposal cost of 22 million USD, the cost disadvantage of MOX production compared to the 'once through' or open cycle disappears theoretically. But not taken into account are the huge initial capital costs for building

26 OECD (1994) estimated the reprocessing cost of UOX fuel rods at 860 ECU or USD/kg HM (OECD 1994, 12) and the manufacturing cost of MOX fuel at 1,100 ECU or USD/kg HM (OECD 1994, 41). Bunn et al. (2003) indicated prices (= 20% surcharge on costs) for reprocessing at BNFL (THORP plant in Sellafield, UK) with a range of 1,600 (for 1989) to 2,300 (for 2003) USD and at the French COGEMA (today: AREVA, plant UP3 in La Hague) between 1,700 to 1,800 (for 2003) USD per kg/HM). The cost of the Japanese plant under construction (UP3 replica in Rokkashomura) was estimated at 2,300-4,100 USD (without and with financing cost) per kg/HM (Bunn et al. 2003, 29). The price of MOX production in the US was estimated at 1,900-2,400 USD/kg HM for the '80s and 2,100 to 2,700 USD/kg HM for the '90s. EDF paid an estimated 1,200-1,240 USD/kg HM to COGEMA (MELOX plant in Marcoule) in the '90s (Bunn et al. 2003, 50). Bunn et al. concluded that – even at conservatively estimated cost for the reprocessing of 1,000 USD/kg HM, the disposal of residues of 200 USD/kg HM, the MOX production of 1,500 USD/kg HM, the alternative uranium enrichment of 1,235 USD/kg and the direct interim and final storage of the uranium fuel of 600 USD/kg HM – the processing (or production) of plutonium only becomes cheaper than the immediate final storage and replacement of the fuels via uranium enrichment, when the price for natural uranium exceeds 360 USD/kg (i.e. reaches almost eight times the current market price). Under the same assumptions, it will only become cheaper to use MOX fuels in a fast breeder (FBR) vs. enriched uranium in a light water reactor (LWR) if the price of natural uranium is higher than 340 USD/kg (Bunn et al. 2003, ix). MIT (2013) calculated that, in order to make MOX fuels cheaper than UOX fuels, the price of uranium had to rise to 560 USD/kg, the cost of reprocessing UOX fuel rods had to fall from 1,000 USD/kg HM to USD 90/kg HM, interim and final storage cost for UOX fuel rods had to increase from 400 USD/kg HM to 1,130 USD/kg HM and interim and final storage cost for highly radioactive residues from reprocessing had to fall from 300 USD/kg HM to 100 USD/kg HM (MIT 2003, 148).

27 Author's calculation based on WISE Uranium Project 2009c.

28 7.1 million USD for the source material − 7 million USD surplus reprocessed uranium usable for enrichment/fabrication + 49 million USD for MOX fabrication.

MOX fabrication facilities – currently estimated at about 10 billion USD (DOE 2016, 2) –, the cost of NPR conversion for MOX use, the increased material fatigue and radioactivity during MOX use and the disposal during fabrication and after use. In addition to the technical problems of developing FBR and the high risk and cost of operation, it was also the high cost of using MOX in FBR that led to the discontinuation of FBR development programmes worldwide (with the exception of Russia, India and Japan).

Japan is currently the only country that does not yet have its own nuclear weapons, although being allowed to process nuclear fuels to produce plutonium and to use it for generating electricity.[29] Since the mid-'50s, Japan's government has claimed its own nuclear reprocessing capacities and sought to establish a domestic 'cycle' for the production of plutonium (Suzuki 2006, 190). Initially, the aim was to become independent of uranium imports (Koide 2011a, 124-8). At the same time – contrary to the basic anti-nuclear principles of not producing, owning and stationing nuclear weapons – Japan's government tried to ensure technological control of the related processes, the availability of facilities for the production of nuclear weapons and the supposedly associated prestige in international relations.[30] However, because nuclear reprocessing is complex and costly, Japan's government decided in 1966 to import the technology from France. France granted Japan the right to reprocess nuclear fuels in 1973. The first reprocessing plant went into test operation in Tōkaimura (Ibaraki Prefecture) in 1977. It was operated by the state-owned Power Reactor and Nuclear Fuel Development Corporation (PNC) and planned to have a processing capacity of 210 t per year. The US government allowed Japan a processing volume of only 99 t in two years with respect to uranium from the US (Suzuki 2006, 195-6). But more than ten Japanese NPPs were already in operation in 1976, and another ten were to go into operation at short notice. Thus, a solution had to be found for the back-end problem. Japan's government insisted on processing fuel and not storing it 'once through'. In 1977, the Japanese NPP operators commissioned French COGEMA (now AREVA) and a year later British BNFL to reprocess their spent nuclear fuels until sufficient reprocessing capacities were available in Japan (planned for the late '90s). However, Japan had to take back not only plutonium and uranium, but also all other radioactive residues.[31] In

29 The reprocessing plants in Germany (Hanau) and Belgium (Dessel, operated jointly with France) have been shut down since 1991 and 2006 respectively. Urenco's reprocessing facility in Almelo (Netherlands) and in Gronau (Germany) are enriching uranium, and Areva's nuclear fuel plant in Lingen (Germany) is fabricating LWR-UO fuel (WISE-Uranium 2009d; Buckner, Burchill 2016, 43).

30 Yamaoka 2011, 80-186; Yoshioka 2011b, 41; Suzuki 2006, 83, 192.

31 As of February 2009, Japanese NPP operators had commissioned the reprocessing of a total of 7,100 t spent fuel. From 1995 to 2007, 524 t (in 1,310 glass containers with a payautumn 1987, the Japanese government under prime minister Yasuhiro Nakasone entered negotiations with the US government under Ronald Reagan and obtained the right to reprocess nuclear fuel rods, to possess, use, store and transport plutonium for the purpose of electricity production from 1988 to 2018 (with automatic extension and termination in six months after notice by one of the two sides), i.e. to own and use the plutonium supplied by France and the UK and produce plutonium themselves.[32]

The consequences of the expansion of NPPs in the ’70s, the temporary commissioning of foreign companies to reprocess and the related taking back of plutonium from abroad prompted METI and the electric power companies in the early ’80s to start planning a domestic ‘nuclear cycle’. But to legitimise plutonium production both internally and externally, the prospect of using this plutonium in FBR was needed.[33] In foreign and security policy, Japan’s government had to prove that plutonium was used exclusively for civilian purposes. Domestically, it had to prove that production and use of plutonium in Japan would reduce the energy dependency on foreign supply at acceptable costs. Supported by the state, the subsidiary of the electric power companies JNFL was supposed to conduct uranium enrichment, reprocessing and interim storage and to build the necessary facilities in Mutsu and Rokkashomura (Aomori Prefecture, 20 km north of the military training area of Amagamori, belonging to the US Air Force base Misawa). The reprocessing plant was planned to have a capacity of 800 t/y with construction costs of 700 billion JPY and a start of operations in 1997. The construction permit was granted in 1989. Construction itself began four years later in 1993. The reprocessing plant was initially

load of 0.4 t each) were returned to Japan (Atomica 2009). In October 1993, the Japanese government published figures on the total plutonium stock for the first time. According to that report, 680 t of nuclear fuel had been reprocessed and 2.9 t of plutonium recovered at the reprocessing facility in Tōkaimura by the end of 1992. 5,770 t of spent nuclear fuel had gone to UK and France, of which 1,870 t of uranium and 4.8 t of plutonium had been processed. Of these, 1.1 t went from France to Japan in January 1993. In addition, 1.2 t of plutonium had been purchased, so that Japan had 5.3 t of plutonium. Of these, 3.7 t were used for the ABWR Fukugen and FBR Monju and 1.6 t were held in reserve (*The Asahi Shimbun*, 2 October 1993, 3).

32 Yamaoka 2011, 183-6; Yoshioka 2011a, 229-30; Suzuki 2006, 196-7.

33 In 1994, the government published its long-term plan for plutonium supply and demand in Japan (AEC 1994). From 1994 to the end of 1999, the research and test reactors Fukugen, Monju and Jōyō were to consume 0.6 t plutonium annually and the reprocessing plant Tōkaimura to provide 0.4 t per year; cumulatively, the supply of 4 t from the reprocessing plant in Tōkaimura and the return from abroad should be offset by a domestic demand of 4 t. For the decade from 2000 to 2010, the demand of 5 t (3 t MOX use in LWR) per year or 35-45 t cumulatively was to correspond to a plutonium production of 5 t annually or 35-45 t cumulatively from the reprocessing plants Tōkaimura and Rokkashomura. The 30 t of plutonium, resulting from future returns from abroad, were to be processed into MOX fuel abroad and consumed in Japan.

test activated in 2006. 25 years after the start of construction, only 425 t of spent nuclear fuel have been converted into 364 t uranium and 6.7 t HM MOX fuel since then (CCNE 2017, 131). To date and after more than twenty plan corrections, the plant does still not work regularly. Practically, its operation has been stopped for a decade and is now planned to restart in 2021 (reprocessing plant) and 2022 (MOX fuel fabrication). The construction costs were initially (in 1993) indicated with 760 billion JPY, corrected in 1996 to 1.88 trillion JPY and in 1999 to 2.14 trillion JPY. In November 2003, the Federation of Electric Power Companies (FEPC) released an estimation of 11 trillion JPY, consisting of 3.37 trillion JPY for construction, 6.8 trillion JPY for 40-year operation and 2.2 trillion JPY for disposal and decommissioning (Kakujōhō 2018). In July 2017, the Nuclear Reprocessing Organisation of Japan (NURO) released an updated estimation amounting to 13.9 trillion JPY (comprised of 4.55 trillion JPY for construction + 7.4 trillion JPY for operation + 2.5 trillion JPY for disposal and decommissioning after 40 years of operation − 0.5 trillion JPY cost savings through rationalisation). The total project cost of the MOX fuel fabrication facility was estimated at 2.3 trillion JPY (NURO 2017). Originally, METI and the electric power companies tended to task French COGEMA/SGN with building a complete UP3 plant (Yoshioka 2011a, 235). But, Japan's government insisted that the technology for glass melt-sealing of highly radioactive substances should be domestic. Since the domestic technology had caused severe trouble since 2007, new versions were installed and tested until 2013. Presently, JNFL tries to meet the new safety standards for nuclear material facilities, introduced in response to 3/11 at the end of 2013: it has built an earthquake-resistant emergency centre, installed large water storage tanks and increased the seismic shock absorption potential of 1,300 km pipelines from 450 gal to 750 gal (CCNE 2017, 131-2). But severe violations of safety regulations were reported and not only were construction and approval again delayed, but also the general feasibility of starting operation questioned (Sawai 2018, 77-8).

From the late ’60s to 1996, the State Science Agency and the PNC spent 1.2 billion JPY on trying to develop their own uranium enrichment, fast breeder and reprocessing technology. These attempts failed more or less, and the implementation plans were postponed several times. At the beginning of related R&D in 1967, the fast breeder was supposed to be ready for operation in the early ’80s, whereas the 2005 ‘Guidelines on Nuclear Policy’ stated that the first fast breeder was to start commercial operation in 2050 (Koide 2011a, 130). In addition, several serious accidents occurred in the late ’90s in the State Science Agency's area of responsibility. In 2001, the agency was dissolved as an independent ministerial department and its remaining sector, the FBR development, integrated into the MEXT. This put an end to Japan's bipolar organisation of state nuclear policy (split between METI and State Science Agency).

Since then all decision-making power and resources for the control and promotion of nuclear policy have been with METI. However, stopping the FBR development would deprive reprocessing or plutonium production of its justification, at least as long as it is cheaper to enrich natural uranium instead of using MOX fuels and employ it as nuclear fuel in LWR. This explains why, despite repeated accidents and delays, the FBR pilot reactor Monju had not been decommissioned until December 2016. And neither the domestic FRB development programme nor the plan to use FBR commercially, have been abandoned officially. But commercial FBRs cannot be expected to consume most of the expensive MOX fuel in the near future. This raises doubts about commercially operated reprocessing in terms of product and process technology as well as business management (Takubo 2017). Considering the up-front and exit costs of a nuclear reprocessing plant, operators can only switch from test to full commercial operation, if three conditions are met: The existence of short and medium-term demand for MOX fuels, the possibility of shifting cost to electricity price, and the opportunity to set up tax-free provision to the extent that the higher costs for the production and consumption of MOX fuel in LWR are covered and a return on the capital tied up in the construction and operation of the reprocessing plant is secured. Long-term demand for plutonium by the next generation of NPPs must also be guaranteed.

In the ’90s, NPP operators tested the use of MOX fuel in LWRs for the first time in order to consume the plutonium coming back from France and the UK. In 1991, the plan was to use MOX fuel in two LWRs until the mid-’90s, in 12 LWRs after 2000 and in 15 LWRs by 2010 (*The Asahi Shimbun*, 18 February 1994, 1). In 1997, METI and the electric power companies decided to use MOX fuel in 16 to 18 reactors by the end of 2010. Their plutonium consumption would have corresponded to the capacity of the Rokkashomura reprocessing plant. However, the use of MOX fuel in LWRs was so difficult and costlsy[34] that in 2009 FEPC postponed the implementation of the plan by five years (Koide 2011a, 135). In 2004, METI calculated the total cost of reprocessing in Rokkashomura in a way that allowed the

34 Yoshioka (2011a) reports that severe quality defects were discovered in MOX fuel rods imported from Belgium and the UK, in 1999, and that the MOX deployment had to be postponed until 2009, that is, a time when MOX fuelled operation of the no. 3 reactor at the Genkai NPP was scheduled to start (319). MOX fuel rods were used at the NPR no. 3 at the Fukushima-1 NPP, which exploded in March 2011. Presently, they are used in the NPR no. 3 of the Ikata and Genkai NPPs, and in NPR 3 and 4 of the Takahama NPP. Operational difficulties arise in controlling (starting and stopping) MOX-charged reactors. In addition, a MOX PWR fuel chamber is estimated to cost 50-100 million JPY, which is five to ten times more than its UOX counterpart (Yoshioka 2011a, 320; 2011b, 41). Further, in MOX fuels α rays are 150,000 times, neutron radiation 10,000 times and γ rays 20 times stronger than in UOX fuels. Finally, after use MOX fuels have such a high heat that they need to be cooled for 500 years before they can be disposed (Hirose 2010, 257-9).

electricity companies to shift the cost of reprocessing onto the electricity price (METI 2004). It was assumed that the plant will run for 40 years from 2006, that a total of 32,000 t or 800 t UOX (fuel rods from 40 reactors) will be processed and 4,800 t MOX fuel (equivalent to 4,300 t U, 900 billion JPY or 7.5 billion USD) will be produced. It was concluded that a total cost amount of 18.8 trillion JPY Yen arises, of which 11 trillion JPY applied to reprocessing (at 32,000 t HM: 343,750 JPY or 2,865 USD/kg HM), 2.55 trillion JPY to the final disposal of highly radioactive residues, 1.19 trillion JPY to MOX production (at 4,800 t HM: 247,917 JPY or 2,065 USD/kg HM) and 1.01 trillion JPY to the temporary storage of the UOX fuel rods used. Converted over a 40-year term, the back-end cost was estimated at 1.23 JPY/kWh and the 'cycle' cost (front-end + back-end) at 1.83 JPY/kWh. Even if one unrealistically assumes that the reprocessing plant in Rokkashomura will be operating at 100% capacity for over 40 years, further capacities would have to be created to reprocess all the spent nuclear fuel of about 1,000 t HM/year produced in Japan's NPPs.[35] Further huge costs loom ahead. An answer to criticism was that without reprocessing, NPPs would have to cease operation and then incur replacement cost that exceeded the additional costs of reprocessing compared with uranium enrichment, one-off use and final disposal (Kikkawa 2011, 148).

The legislation necessary for the start of reprocessing was passed in 2005. The NPP operators had already formed provisions for covering future reprocessing expenses from part of the electricity price or their related sales income since 1982. Amounting to 3.14 trillion JPY by March 2005, these provisions were now released, transferred to the Radioactive Waste Management Funding and Research Centre (RWMC) and called up from there by the NPP operators to pay JNFL until 2016. Thus, JNFL was able to indicate an average annual sales income of about 300 billion JPY, of which 90% were declared income from reprocessing spent nuclear fuel, although reprocessing still did not operate at a feasible commercial scale. In other words, JNFL took related payment from the NPP operators in advance. NPP operators paid (that is, they released provisions out of charges for reprocessing) 500-600 billion JPY/year into RWMC from FY2005 to FY2015. These funds for the reprocessing business, included in the electricity price and therefore finally paid by electricity consumers, amount to ca. 0.50-0.60 JPY/kWh.[36] In 2004 the total back-end costs (including reprocessing) were estimated by the government at 18.8 trillion

35 Given a consumption of 30 t UOX/a at 1 GW NPR, before 3/11 NPP capacity of 49 GW and NPP utilization rate of 70%, this would result in an annual accumulation of 1,029 t UOX spent nuclear fuel.

36 Following Ōshima, 600 billion JPY/year divided by sold electricity of 100 TWh/year = 0.6 JPY/kWh (Ōshima 2010, 97).

JPY (METI 2004). But if converted to the total electricity volume of all NPPs installed and operating before 3/11 (49 GW, 40 years running time, 70% utilization: 12,019 TWh), back-end costs (without reactor decommissioning but with final disposal) are actually 1.56 JPY/kWh. However, the construction delays in Rokkashomura and the cost increases to date as well as the lack of considering future expenses suggest that significantly higher costs are to be expected here.

Officially related to the liberalization of the retail market for electricity, this extremely in-transparent provision scheme was changed into a contribution scheme in 2016. Now, the Nuclear Reprocessing Organisation of Japan (NURO), a public corporation, commissions not only reprocessing, but also fuel fabrication and disposal to JNFL, and it is supposed to charge the NPP operators with a contribution fee to cover the cost of commissioning JNFL. Independent critics like the Citizens' Commission on Nuclear Energy (CCNE) regard this new scheme not as a measure to improve transparency and avoid conflict of interest, but as a step towards shifting the responsibility and financial risk for the back-end management to the public, respectively lifting burdens from NPP operators – after all, NURO's responsibilities extend from reprocessing to the complete back-end. Letting the grid operators charge back-end cost after the formal separation of electricity generation and distribution from 2020 onwards, not only NPP operators, but all electric power generators and consumers will have to shoulder these costs (CCNE 2017, 133-4). In order to present reprocessing as being without alternative, the Japanese government has not answered yet to the issue of final disposal. Obviously, it tried to wait until the reprocessing of UOX fuel rods, the production and use of MOX fuel and FBR had started and MOX fuel was used in LBR. However, a continuous investment in plutonium production raises only the cost of an eventual exit. Once the production of fissile plutonium has started, a pressure builds up to use it in NPPs (whether LWR or FBR) and, due to the growing quantity, create further application possibilities in form of new NPPs or the production of nuclear weapons. Conversely, from the perspective of the proponents of reprocessing, the final disposal of highly radioactive substances must not function until reprocessing has started. Otherwise, reprocessing could not be justified as the only feasible and least expensive way of coping with spent nuclear fuel. It is therefore no coincidence that the issue of final disposal is not being proactively addressed, although highly radioactive residues are generated by the running NPPs, returned from France and the UK, and 19 among 57 once operated NPRs (as of 7 June 2018) are already being or will be dismantled.

In 2000, the Nuclear Waste Management Organisation (NUMO) was established, its costs and investments being paid by RWMC from provisions of the NPP operators.[37] By 2003, five candidate sites were to be nominated and one site was to be selected by 2020 to begin final disposal in 2040. Since 2002, candidate sites have been sought, and municipalities willing to apply for preliminary investigations have been offered subsidies of 9 billion JPY as well as property tax revenues of 2.9 billion JPY per year after start of operations (NUMO [2012] 2018b). According to reports some municipalities considered an application, but so far respective initiatives have failed to secure consent by the majority of their citizens. Consequently, there was no candidate site that could have entered the test drilling phase in August 2011 (Yoshioka 2011a, 353-4). But applicants for the trial wells were to be found by 2015 in order to start the construction of a plant at a depth of 300 m with a capacity of 40,000 containers (150 l/net 400 kg each) at the beginning of the 2030s. In July 2017, with a delay of six months, a 'map of preferred candidate sites based on scientific analysis' was officially released by the government to enhance further promotion by NUMO.

The costs for final storage were estimated by METI in 2004. Converted to the expected volume of electricity (with a 2% discount rate for capital cost) they amounted to 0.14-0.32 JPY/kWh.[38] However, rising construction costs and expected construction delays make the whole thing much more expensive. METI and the electric power companies have so far committed themselves to plutonium production. A disposal site will not be available in the near future. But neither do domestic reprocessing facilities work nor are FBRs in operation. Therefore, old fuel rods must remain in the NPPs' cooling basins, which will soon reach the limits of their capacity (tab. 3.1).

37 In FY2015, electric power companies paid 68 billion JPY for final disposal vs. 131 billion JPY for reprocessing. Cumulative in-payments for provisions amounted to 1 trillion JPY vs. 5 trillion JPY for reprocessing to RWMC (RWMC 2015).

38 In order to calculate the final disposal costs, one can refer to the MIT study of 2003 and assume that – as it is currently the case with a one-way cycle and plutonium reuse – UOX and MOX fuels in a ratio of 2.5:97.5 are used, which then – with a current total of 49 GW nuclear power capacity – results in 25 t spent MOX and 820 t spent UOX fuel and as remainings from plutonium production in 123 t separated uranium, 45 m^3 process residues, 15 m^3 glass, 7 t of high-level radioactive waste, plutonium and residual actinide from plutonium production or UOX reprocessing (MIT 2003, 127). MIT (2003) sets the intermediate and final storage costs for used fuel rods at 400 USD/kg HM and for high-level radioactive waste (HWL) at 300 USD/kg HM (MIT 2003, 151). This would have resulted in intermediate and final storage costs of 388 million USD or 45.4 billion JPY (= 338 million USD + 50 million USD, 2007 exchange rate: 117 JPY/USD) per year or 0.15 JPY/kWh. Assuming that all UOX fuels were reprocessed, MOX fuels were used only one time and nuclear power reactors are fueled with both fuels in a 16:84 ratio of MOX to UOX fuel, running 49 GW of nuclear power capacity one year would leave 156 t of spent MOX and as remainings from plutonium production or UOX reprocessing 767 t separated uranium, 287 m^3 of process residues, 94 m^3 of glass, 43 t of highly radioactive waste, plutonium and residual actinide from reprocessing (plutonium production) (MIT 2003, 121). This translates into final disposal costs of 376 million USD or 44 billion JPY (62.4 million USD + 313.5 million USD) or 0.146 JPY/kWh.

Table 3.1 Spent fuel storage capacity (cooling pools) at NPP sites (as of 2017)

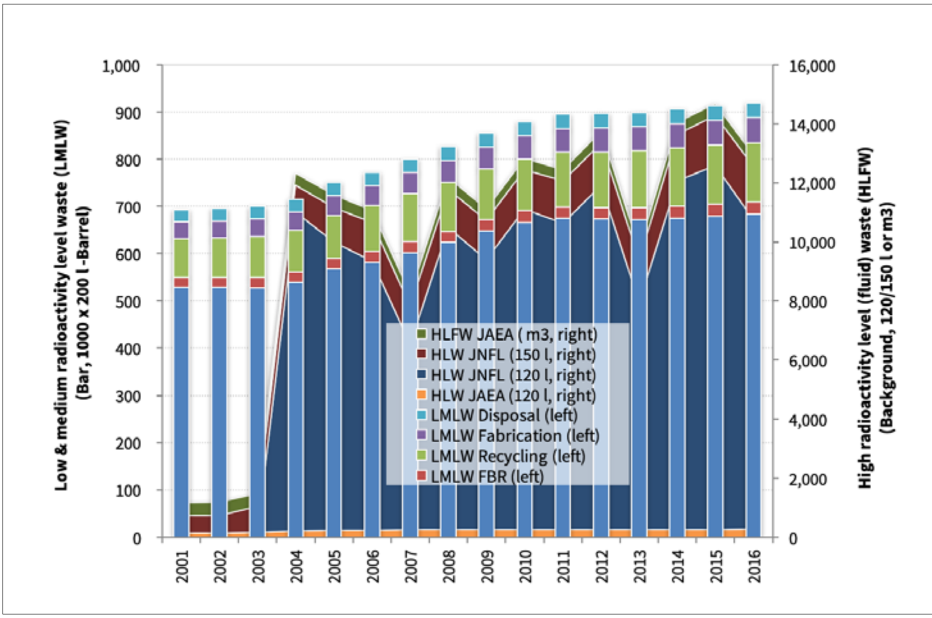
	Loaded fuel (t U)	Annual reload (t U)	Spent fuel stock (t U)	Storage capacity (t U)	Left capacity (years)
Tomari	170	50	400	1,020	**9.0**
Onagawa	260	60	420	790	**1.8**
Higashitōri	130	30	100	440	**7.0**
Fukushima 1	580	140	2,130	2,260	**-3.2**
Fukushima 2	520	120	1,120	1,360	**-2.3**
Kashiwazaki	960	230	2,370	2,910	**-1.8**
Hamaoka	410	100	1,130	1,300	**-2.4**
Shiga	210	50	150	690	**6.6**
Mihama	70	20	470	760	**11.1**
Takahama	290	100	1,220	1,730	**2.2**
Ōi	360	110	1,420	2,020	**2.2**
Shimane	100	40	460	680	**6.0**
Ikata	120	50	670	1,020	**5.8**
Genkai	230	50	900	1,130	**0.0**
Sendai	150	50	930	1,290	**4.4**
Tsuruga	90	30	630	910	**6.3**
Tōkai 2	130	30	370	440	**-2.0**
all NPP	**4,780**	**1,260**	**14,890**	**20,750**	**0.85**

Left capacity = (Pool Capacity — Fuel Load)/Annual Reload; fuel load and reload based on: METI 2018; spent fuel stock and pool capacity based on: FEPC 2017

In 2011, the electric power companies estimated the shortage of interim storage that had already occurred by 2010 at 4,400 t/U and the total demand for additional capacities 2011-2020 at 7,100 t/U (FEPC 2011, 7-27). Although Rokkashomura is still not in commercial operation, 3,393 t or 13,771 rods of spent UOX fuel have been stored there from July 2009 until the end of March 2018 (JNFL URL). 425 t of these have been test-wise reprocessed (CCNE 2017, 131). The remaining of 3,400 t UOX corresponds to the quantity that is generated in Japan's NPPs under normal operational conditions over a period of three years. Thus, the current storage capacity of 3,000 t at Rokkashomura (final plan: 5,000 t) has been exhausted already. This means that Japan is literally overflowing with spent nuclear fuel and radioactive residues (charts 3.17, 3.18).

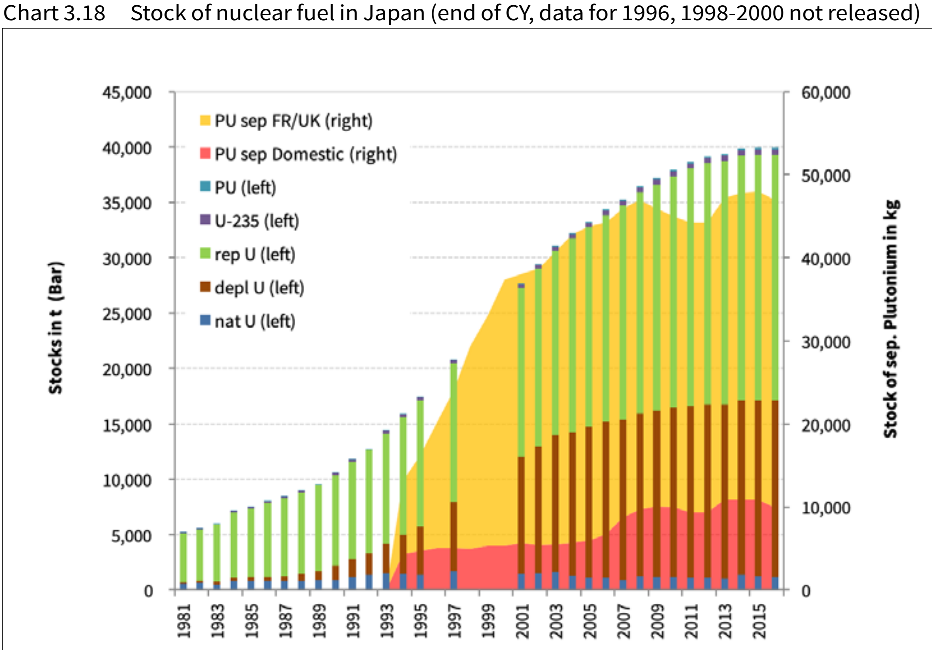
After 16 years of operation, NPPs are depreciated to the residual accounting value of 10% and become more profitable, because depreciation costs do almost not occur anymore. However, the costs for the construction of new NPPs are considerably high, estimated at 440,000 JPY/kW in 2001, but exploding towards 1,000,000 JPY/kW over the last years (Hiro-

Chart 3.17 Volume of nuclear waste in Japan (end of FY)



Source: Author, based on JNES 2004-2011; NRA 2012-2016

Chart 3.18 Stock of nuclear fuel in Japan (end of CY, data for 1996, 1998-2000 not released)



Source: Author, based on AEC 1994, 2018

shi Takahashi 2017, 147).[39] METI and the NPP operators have therefore been trying to extend NPP operating times – first to 40 years, then to 50 years and finally even to 60 years (Takagi 2000b, 172-4).[40] Nevertheless, the GCR reactor (166 MW) at the Tōkai NPP (1998), the ATR reactor (166 MW) Fugen (2003) and the reactors nos. 1 (540 MW) and 2 (840 MW) at Hamaoka NPP (2009) had been closed down already before 3/11. After 3/11, it was decided to decommission 12 more NPRs: nos. 1-6 (4,696 MW) of the Fukushima-1 NPP, no. 1 (460 MW) of the Shimane NPP, NPR no. 1 (357 MW) of the Tsuruga NPP, nos. 1-2 (840 MW) of the Mihama NPP, no. 1 (566 MW) of the Ikata NPP and no. 1 (559 MW) of the Genkai NPP. Additionally, the shut-down of the FBR Monju was decided in December 2016 (CCNE 2017, 157-8). They all have to be dismantled and their radioactive components stored temporarily as well as permanently. Assuming that 100% of the total mass of 500,000 t must be treated as contaminated when dismantling one NPR with a standard capacity of 1 GW, CNIC has estimated the decommissioning costs of one NPR in the late '90s at 632 billion JPY (which corresponds to 150-200% of the then construction cost). By contrast, METI assumed at the same time that 95% of the volume mass could be classified as non-radioactive or low-level-radioactive and therefore disposed of cheaply, so that the decommissioning costs amounted to only 26.3 billion JPY (Takagi 2000b, 284-5). The NPP operators assumed in 2011 that 0.536 million t of residual waste will be produced if a 1,100 MW BWR is dismantled. Of these, 93% (0.495 million t) were said to be non-radioactive concrete, 5% (28,000 t) 'clearance material' (i.e. radioactive to an officially safe extent), only 2% (13,000 t) low radioactive and less than 0.1% (540 t) highly radioactive residual material (FEPC 2011, 9-2).

39 METI estimated these costs in 2015 extremely low at 370,000 JPY/kW, using NPRs built before 2011 as reference (CCNE 2017, 222; Matsuo, Nei 2018, 33). The costs for ongoing or recently stopped construction of APR 1000 NPRs in the US are said to have doubled in current projections towards 1,150,000 JPY/kW or 11,000 USD/kW excluding financing cost and 1,300,000 JPY/kW or 12,500 USD/kW including financing cost (Cooper 2017). The total cost projection (as of July 2017) for EDF's NPP at Hinkley Point C in the UK (3.2 GW, to be completed in 2025) amounts to 994,000 JPY/kW or 6,500 GBP/kW (*The Guardian Online*, 03 July 2017). Current estimations are reported to have resulted in 1.13 million JPY/kW as of July 2018 (*Tōkyō Shimbun Online*, 14 July 2018). By referring to building permission related data, Matsuo and Nei support METI's current cost estimations. They maintain that capital costs of NPR differ considerably by country, that these costs have risen only slightly in Japan, reflecting general increase of labour cost, and are fundamentally lower than in Europe and the US due to economy of scale (building multiple large NPR) even if taking into account additional safety cost. But they concede that a longer construction (lead) time might result in considerable cost increases (Matsuo, Nei 2018, 27, 33).

40 The average lifespan of the 130 NPRs that were shut down worldwide right after 3/11 was 22 years (as of April 2011), while that of the 437 NPRs still in operation at the same time was 26 years (Schneider 2011; Schneider et al. 2011, 11). The respective data as of July 2017 are 25.2 years for 169 NPRs shut down and 29.3 years for 403 NPRs operating (Schneider et al. 2017, 37-9).

Since 1989, decommissioning costs in Japan have been paid by consumers as part of the electricity price and retained by producers as provisions. In 2007, the decommissioning costs for a BWR with 1.1 GW were estimated at 65.9 billion JPY (60,000 JPY/kW) and for a PWR of the same capacity at 59.7 billion JPY (54,000 JPY/kW) (FEPC 2007). This translates into 0.22-0.25 JPY/kWh converted to the volume of generated electricity to be expected in 40 years at a 70% capacity utilization. However, cost estimates for NPRs already being in the process of dismantling are considerably higher in Japan.[41] In the US and the UK, decommissioning costs were estimated before 3/11 to be two to four times higher than in Japan, that is, at a range between 1,000 USD/kW (117,000 JPY/kW) (Moody's 2008) and 1,750 USD/kW (204,750 JPY/kW) (British Energy 2008).

Apart from the continuing inoperability, unreliability and danger of key elements of the so-called nuclear cycle in Japan, this section demonstrated that the costs for the front-end can be estimated at 0.76-1.15 JPY/kWh[42] and for the back-end at 2.36-2.80 JPY/kWh.[43] At 3.12-3.95 JPY/kWh, these costs are 1.29-2.12 JPY/kWh higher than the 'cycle costs' of 1.83 JPY/kWh officially reported since 2004 for the reprocessing variant that METI and the NPP operators pursue. However, not all costs are taken into account, especially not those that occur afterwards and will affect future generations.

3.3.3 Actual Costs of Nuclear Power Generation: Complex, Hidden and High

Japan's government and NPP operators have been claiming that NPPs are the most cost-effective form of electric power generation. But how much does nuclear power generation actually cost? The costs of electricity production are converted into the amount of electricity generated and are thus heavily dependent on running time and capacity utilization. They consist of fixed and variable costs or of costs for capital (depreciation, interest, share of costs for joint investment, taxes on fixed assets), fuel, operating and maintenance. An important point in calculations and comparisons is which costs to take into account and how to define their individual components. Cost components as well as their share in and their impact on the total cost differ according to type of power generation: in thermal power plants, fuel and CO_2 emission costs are high, so that fuel price changes have a major

41 The dismantling of the GCR reactor (166 MW) at the Tōkai NPP will cost 88.5 billion JPY (*Bloomberg News*, 30 March 2011). Chūbu Electric Power (CEP) estimates 100 billion JPY for each of NPR nos. 1 and 2 of the Hamaoka NPP (*The Yomiuri Shimbun*, 31 March 2011).

42 UOX with 0.65 JPY/kWh, MOX with 1.95 JPY/kWh (UOX/MOX: 97.5/2.5 or 84/16).

43 Decommissioning: 0.50 JPY/kWh, reprocessing: 1.56-2.00 JPY/kWh, disposal: 0.30 JPY/kWh.

impact on the total cost. In the case of nuclear and hydroelectric power plants, the construction and capital costs are so high that the risk and return expectations of capital providers reflected in the discounting rate, depreciation, and the lifespan and utilization of assets play a major role.[44]

The costs of electricity generation by power plant type are determined either deductively by means of the so-called model power plant or inductively and retrospectively on the basis of the cost data in the financial reports of the electric power companies. The deductive method has the advantage of equating all external factors with the influence on the total cost and objectifying the comparison. The disadvantage is to be dependent on the setting of the model conditions; that is, why projections do not necessarily reflect the actual costs incurred. Assuming optimistically correct data reporting and consistent methodology, the advantage of the inductive method is that it empirically captures the costs, their components and their changes in the past. Extrapolations are possible only under the extremely restrictive assumption that the past continues linearly into the present and the future.

The deductive projections compiled in table 3.2a have in common that they often refer to a maximum of a 40-60 year lifespan and do not take into account systemic or social costs (e.g. government subsidies and guarantees). In these projections the costs of nuclear power are heavily dependent on how the costs of capital (construction and financing) are calculated and what discount rate is applied: normally, 3%, 5% and 10% risk premium are indicated. But NPP proponents, namely, government, NPP operators and their allies, tend to report only costs that are based on the lowest discount rate. Thus, the cost of NPP-generated electricity appears lower compared to all other power plant types at lower discount rates (Takemori 2011, 12-48).[45] METI and OECD apply this discounting method

44 The 2015 OECD report indicates the ratio of capital, fuel, CO_2 and operating costs of conventional power plants in Japan (2013) by generation type at a 3% discount rate as follows: (a) NPP = 34% capital + 23% fuel + 44% operations, (b) coal-fired power plants = 16% + 64% + 20%, (c) gas-fired power plant = 7% + 86% + 7%, (d) large hydropower plants = 78% + 0% + 22% (OECD 2015, 47-55). In the 2010 OECD report edition, the data for conventional power plants in Japan (2009) were indicated as follows: (a) NPP = 48% capital + 19% fuel + 33% operations, (b) coal-fired power plants = 26% + 63% + 11%, (c) gas-fired power plants = 26% + 63% + 11%, (d) large hydropower plants = 76% + 0% + 24% (OECD 2010, 59-62). The OECD projection of 2004 (2005 edition) did not take CO_2 emission costs into account, which reduced the share of fuel costs: (a) NPP = 45% capital + 25% fuel + 30% operation, (b) coal-fired power plants = 42% + 40% + 18%, (c) gas-fired power plants = 28% + 63% + 9%, (d) large hydropower plants = 78% + 0% + 22% (OECD 2005, 52, 61).

45 In its 2015 edition the OECD report indicates also cost data for a 7% and 10% discount rate, reflecting a deregulated or restructured market environment respectively and a 10% discount rate reflecting a high investment-risky environment. At a discount rate of 10%, the total cost median of NPPs for all covered countries becomes higher than that of CCGTs or coal-fired thermal power plants. For Japan, the projected cost advantage of NPPs at a uniformly to all types of power plant; risks or investment characteristics specific for a certain type of electricity generation or power plant are not taken into account. Applying a lower or the lowest discount rate creates also the impression that the Japanese government takes on all relevant NPP-related risks.

Table 3.2a Deductive projections of electricity costs by power plant type

	MIT 2003	UC 2004	UC 2004	METI 2004	CNIC 2005	OECD 2005	MIT 2009	OECD 2010	METI 2011	OECD 2015	METI 2015	EIA 2017
Region	US	US	US	Japan	Japan	Japan	US	Japan	Japan	Japan	Japan	US
Price base	2002	2003	2003	2002	2003	2003	2007	2009	2010	2013	2014	2017
Operation	40	40	40	40	40	40	40	60	30/40/50	60	40/60	30
Load	85	85	85	80/40	80/45	85/45	85	85/45	80/70/45	85/45	70/80	87/90
Discount rate	11.5/ 9.6	12.5/ 9.5	12.5/ 9.5	0/1/3/4	3.5/6.3/ 4.2/2/0.3	5/10	11.5/ 9.6	5/10	0/1/3/5	3/7/10	3	4.5
¥/$	-	-	-	122	104	119	-	103	86	103	105	
Nuclear build cost	2.0k $/kW	1.5k $/kW	1.5k $/kW	279k ¥/kW	286k ¥/kW	2.51k $/kW	4.0k $/kW	3.0k $/kW	350k ¥/kW	4.3k $/kW	370k ¥/kW	5.9k $/kW
Coal build cost	1.3k $/kW	1.2k $/kW	1.2k $/kW	272k ¥/kW	224k ¥/kW	2.35k $/kW	2.3k $/kW	2.7k $/kW	293k ¥/kW	2.6k $/kW	250k ¥/kW	5.6k $/kW
Oil build cost	-	-	-	269k ¥/kW	199k ¥/kW	1.5k $/kW	-	1.5k $/kW	220k ¥/kW	-	200k ¥/kW	2.1k $/kW
Gas build cost	0.5k $/kW	0.3k $/kW	0.3k $/kW	164k ¥/kW	153k ¥/kW	1.29k $/kW	0.9k $/kW	1.5k $/kW	137k ¥/kW	1.3 k $/kW	120k ¥/kW	1.1k $/kW
Hydro build cost	-	-	-	732k ¥/kW	757k ¥/kW	7.0k $/kW	-	8.4k $/kW	700k ¥/kW	9.7k $/kW	640k ¥/kW	
Nuclear power cost	6.7 c/kWh	5.4 c/kWh	5.4 c/kWh	5.3 ¥/kWh	5.73 ¥/kWh	4.8 c/kWh	8.4 c/kWh	5.7 c/kWh	8.9-10.2 ¥/kWh	6.3 c/kWh	10.1 ¥/kWh	9.0 c/ kWh
Coal power cost	**4.4** c/kWh	**3.3-4.1** c/kWh	**3.3-4.1** c/kWh	**5.7** ¥/kWh	**4.93** ¥/kWh	**4.9** c/kWh	**6.2** c/kWh	**8.8** c/kWh	**9.5-10.6** ¥/kWh	**9.5** c/kWh	12.3 ¥/kWh	**11.9** c/ kWh
Gas power cost	**4.1** c/kWh	**3.5-4.5** c/kWh	**3.5-4.5** c/kWh	**6.2** ¥/kWh	**4.88** ¥/kWh	**5.2** c/kWh	**6.5** c/kWh	**10.5** c/kWh	**10.7-11.4** ¥/kWh	**13.3** c/kWh	**13.7** ¥/kWh	**4.8** c/ kWh
Oil power cost	-	-	-	**10.7** ¥/kWh	**8.76** ¥/kWh	-	-	-	**20.8-26.7** ¥/kWh	-	**30.6** ¥/kWh	-
Hydro power cost	-	-	-	**11.9** ¥/kWh	**7.20** ¥/kWh	**14.3** c/kWh	-	**15.3** c/kWh	**10.6** ¥/kWh	**11.0** c/kWh	**11.9** ¥/kWh	-

Source: Compiled by Author

3% discount rate evaporates almost completely in comparison to coal-fired power plants (OECD 2015, 14, 27-8).

Nevertheless, the small differences raise doubts. Already in 2005, CNIC took the inductive approach to check the assumptions: using the power plant costs of 1993-2003 as indicated in the financial reports, they found significant differences in relative construction costs. CNIC came to the conclusion that NPPs in Japan (as in the US) are not the least expensive type of power plants, but far more expensive than coal or LNG fired power plants (CNIC 2005, 8/9, 13). The OECD 2010 and 2015 projections, like MIT's sub-scenarios of 2003 and 2009, took into account the cost of CO_2 emissions from coal and gas-fired thermal power plants, but assumed a lifespan of 60 years for NPPs and a 85% utilization (OECD 2010, 43, 45; OECD 2015, 30-1).

As early as 1985, Kumamoto criticised the METI projections of 1984 – and later those of 2004.[46] He showed that equalizing the degree of utilization of NPPs and coal-fired power plants is unrealistic and renders the costs of nuclear power unreasonably low.[47] Furthermore, he pointed out, that one cannot assume electricity to be produced in the so-called best mix (i.e. the combined use of different types of production for different demand times and levels) but concurrently (a) abstract from it the cost comparison of different types of production, (b) assume equal utilization levels and (c) claim nuclear power to be the cheapest. It is also important whether the costs relate to the start of operation, the statutory depreciation period or the entire investment life, because production types with a high fixed or capital cost component appear to be cheaper the longer the period under consideration.[48] Based on the historical average of utilization levels of different generation types, nuclear power is more expensive than that produced in coal and gas power plants (Kumamoto 2011, 74-103). The actual utilization rate of NPRs in Japan was 66% during 1970-2010 and 58% during 1970-2017 (vs. 85% assumed by OECD and 80% assumed by METI (2004).[49] The same applies to the lifespan of the power plants, which most projections by METI set at 40 years, OECD projections even at 60

46 METI (2004) is actually a projection submitted by FEPC (2004), which has been referenced by government committees (METI/AES) to justify the government's energy and nuclear policies, particularly with regard to the nuclear fuel cycle (front-end and back-end).

47 Both power plant types are used in the so-called baseload coverage are relatively capital-intensive. However, coal-fired power plants are technologically mature, less prone to failure and of a much higher capacity utilization than NPPs (85% vs. 60%).

48 Critics of nuclear power usually counter the running-time-related cost projections with the start-up costs that the NPP operators specified in the '70s and '80s to apply for planning permission (Datsugenpatsu nyūmon kōza 2011; Genshiryoku kyōiku o kangaeru kai 2008). This is legitimate insofar as these initial costs enter into the electricity price calculation as such and have to be paid by the customers.

49 For the actual trend of the average NPP/NPR utilization rate in Japan, see chart 3.16.

years.[50] The average lifespan of the 15 NPRs closed down in Japan was 36 years. In this respect, cost calculation should be realistically limited to the statutory depreciation period of 20 years. In December 2017, CNIC reviewed the METI cost projection of 2015 (based on a 2014 model plant) and undertook a correction, reflecting (a) the decline of fuel prices from 2014 to 2016 for coal (−0.99 JPY/kWh) and LNG (−5.14 JPY/kWh), (b) the currently admitted increase of NPR-decommissioning cost (+0.16 JPY/kWh) and 3/11-related damage compensation cost (+0.28 JPY/kWh) and (c) the total damage recovery cost estimated by the Japan Center for Economic Research (JCER), which amounts to 50-70 trillion JPY (and translates into +1.1 or +1.72 JPY/kWh). Furthermore, METI set the capital cost for NPRs extremely low at 400 Billion JPY/NPR or 370,000 JPY/kW, compared to currently reported 1 trillion JPY/NPR or 926,000 JPY/kW[51] and reduced the probability of a severe accident (SA) and related costs from 1 SA per 2,000 NPR running years to 1 SA per 4,000 running years. Based on the 2017 projection data for NPR capital cost by the International Energy Agency (IEA) and the foreign currency exchange rate of 2016, the capital cost for NPRs increases actually by 2.5 JPY/kWh. SA-related cost for risk provisions (+0.3 JPY/kWh), decommissioning and damage compensation (+0.28 JPY/kWh or +1.77 JPY/kWh) actually doubles. Consequently, the electricity costs for NPRs rise from projected 10.1 JPY/kWh to 12.26-15.14 JPY/kWh, while those for coal-fired power plants fall from 12.34 JPY/kWh to 11.35 JPY/kWh and those for LNG fired power plants from 13.72 JPY/kWh to 8.58 JPY/kWh (Matsukubo 2017). In view of such realistic assumptions for a deductive cost projection, NPP-generated electricity was considerably more expensive than electricity generated by coal or LNG fired power plants in 2016.

50 For the worldwide average lifespan of previously decommissioned NPPs, see § 3.3.2b.

51 EDF indicated the cost for the Flamanville site (1.63 GW) in France with 6,300 €/kW (794,000 JPY/kW) in 2017. The cost for Olkiluoto-3 (1.63 GW) in Finland were estimated at 5,220 €/kW (540,000 JPY/kW) in 2012 (*Reuters Online News*, 9 October 2017). Hitachi and the British and Japanese governments are reported to design a finance scheme for the Wylfa site (2.7 GW), covering 3 trillion JPY, which translates to 1,111,000 JPY/kW (*Sentaku*, February 2018, 68-71). Hitachi-CEO Hiroaki Nakanishi is reported to have asked the British prime minister Theresa May on 2 May 2018 to inject capital into the project, otherwise Hitachi might withdraw due to exploding cost (*Tōkyō Shimbun Online*, 3 May 2018). The cost estimation for the Sinop site (4.4 GW) in Turkey with participation of MHI was currently corrected from 550,000 JPY/kW to 1,000,000 JPY/kW (*The Asahi Shimbun Online*, 15 March 2018). General trading company Itochū declared its exit from the project, fearing cost and time budget overuns (*Tōkyō Shimbun Online*, 3 May 2018). For further examples see § 3.3.2b.

Table 3.2b Inductive estimations of electricity costs by power plant type before 3/11

	Ōshima 2010		**Ōshima 2011**	**Matsuo et al. 2011**
Covered period	1970-2007	2000-2007	1970-2010	2006-2010
Included cost	Public subsidies for promotion, public R&D-programmes (in brackets)			-
Nuclear	**10.68** 8.64 + (0.40 + 1.64) JPY/kWh	**8.93** 7.29 + (0.46 + 1.18) JPY/kWh	**10.25** 8.53 + (0.26 + 1.46) JPY/kWh	**7.2** JPY/kWh
Thermal	**9.90** 9.80 + (0.02 + 0.08) JPY/kWh	**9.02** 8.90 + (0.11 + 0.01) JPY/kWh	**9.91** 9.87 + (0.03 + 0.01) JPY/kWh	**10.2** JPY/kWh
Hydro	**7.26** 7.08 + (0.06 + 0.12) JPY/kWh	**7.52** 7.31 + (0.10 + 0.10) JPY/kWh	**7.19** 7.09 + (0.02 + 0.08) JPY/kWh	-
Hydro ex. PS	**3.98** 3.88 + (0.06 + 0.04) JPY/kWh	**3.59** 3.47 + (0.07 + 0.05) JPY/kWh	**3.91** 3.86 + (0.01 + 0.04) JPY/kWh	-
Pump storage	**53.14** 51.87 + (0.34 + 0.94) JPY/kWh	**42.79** 41.81 + (0.38 + 0.60) JPY/kWh	**53.07** 52.04 + (0.16 + 0.86) JPY/kWh	-
Nuclear + PS	**12.23** 10.13 + (0.42 + 1.6) JPY/kWh	**10.11** 8.44 + (0.47 + 1.21) JPY/kWh	-	-

Source: Author, compiled from Ōshima 2010, 2011c; Matsuo et al. 2011

Table 3.2c Breakdown of nuclear power cost estimations

<table>
<tr><th></th><th>Ōshima 2010</th><th>Matsuō 2011</th><th>METI 2011</th><th>JREF 2012</th><th>METI 2015</th><th>CNIC 2017</th><th>JCER 2017</th><th>CCNE 2017</th></tr>
<tr><td>Coverage period</td><td>1970-2007</td><td>2006-2010</td><td>Model plant 2010</td><td>Model plant 2010/12</td><td>Model plant 2014</td><td>Model plant 2014</td><td>Model plant 2014</td><td>1970-2010</td></tr>
<tr><td>Method</td><td>Inductive</td><td>Inductive</td><td>Deductive</td><td>Inductive/ deductive</td><td>Deductive</td><td>Inductive/ deductive</td><td>Inductive/ deductive</td><td>Inductive</td></tr>
<tr><td>Nuclear power total</td><td>12.23 ¥/kWh</td><td>7.2 ¥/kWh</td><td>8.9-10.2 ¥/kWh</td><td>11.2-17.1 ¥/kWh</td><td>10.1- ¥/kWh</td><td>12.3-15.1 ¥/kWh</td><td>14.7 ¥/kWh</td><td>13.3 ¥/kWh</td></tr>
<tr><td>Capital cost</td><td rowspan="6"></td><td>1.9 ¥/kWh</td><td>2.6 ¥/kWh</td><td>3.0 ¥/kWh</td><td>3.1 ¥/kWh</td><td>5.6 ¥/kWh</td><td>6.4 ¥/kWh</td><td rowspan="2">8.5 ¥/kWh</td></tr>
<tr><td>Operational cost</td><td>2.7 ¥/kWh</td><td>3.1 ¥/kWh</td><td>3.1 ¥/kWh</td><td>3.3 ¥/kWh</td><td>3.3 ¥/kWh</td><td>5.0 ¥/kWh</td></tr>
<tr><td>Front-end cost</td><td>0.6 ¥/kWh</td><td rowspan="2">1.4 ¥/kWh</td><td rowspan="2">1.4 ¥/kWh</td><td rowspan="2">1.5 ¥/kWh</td><td rowspan="2">1.5 ¥/kWh</td><td rowspan="2">1.5 ¥/kWh</td><td rowspan="4"></td></tr>
<tr><td>Back-end cost</td><td>1.8 ¥/kWh</td></tr>
<tr><td>Decom-mission</td><td>0.3 ¥/kWh</td><td>-</td><td></td><td>-</td><td>In safety/ Risk/</td><td></td></tr>
<tr><td>Pump storage</td><td>-</td><td>-</td><td></td><td>-</td><td>-</td><td></td></tr>
<tr><td>Subsidies R&D</td><td>2.10 ¥/kWh</td><td>-</td><td>1.1 ¥/kWh</td><td>1.8 ¥/kWh</td><td>1.3 ¥/kWh</td><td>1.3 ¥/kWh</td><td>1.3 ¥/kWh</td><td>1.7 ¥/kWh</td></tr>
<tr><td>Safety/risk/ damages</td><td>-</td><td>-</td><td>0.2+(0.4-1.9)¥/kWh</td><td>1.8-6.9 ¥/kWh</td><td>0.9- ¥/kWh</td><td>0.56-3.44 ¥/kWh</td><td>0.4- ¥/kWh</td><td>3.1 ¥/kWh</td></tr>
</table>

Source: Compiled by Author (JPY=¥)

In case of an inductive and retrospective calculation, the results differ only as to whether include systemic (pumped-storage power plants) and external costs (public settlement subsidies, development programmes) (tab. 3.2b). Taken into account these costs, NPPs loose their cost advantage.[52] Table 3.2c

52 Matsuo et al. (2011) criticise Ōshima (2010) for unjustifiably adding the costs of hydro pumped-storage power plants to nuclear costs and not just the difference between hydro pumped-storage power plants and oil-fired thermal power plants (Matsuō et al. 2011, 19). Following this difference, 0.70-0.96 JPY/kWh have to be added to the nuclear power costs of 2010.

shows which components are included in the costs of NPP-generated electricity. Besides the recently escalating, but notoriously underestimated capital costs, the total cost of nuclear power depends on whether and to what degree risk and costs of a severe accident are considered. The related provisions are a function of what has to be covered by these costs (impact or damage scale and scope) and how the probability of a severe accident is estimated.

In October 2011, the government's Atomic Energy Council (AEC) estimated the total loss related to the Fukushima severe accident (SA) at 3.9 trillion JPY (damage compensation: 2.6 trillion JPY, NPP-related losses and decommission cost: 1.3 trillion JPY), under the presumption of a model NPR with 1.2 GW, a 60/70/80% capacity utilization and a 40-year lifespan. The risk and damage-related costs amounted to 1.1 JPY/kW, estimating the continuous wider cost (indirect damages or losses) for the following five years at 3.26 trillion JPY, assuming an SA occurrence probability of 0.2% (representing Japan's historical tracking record with one SA at every 498 NPR running years and 3/11 counted as three) and a NPR load of 70% (AEC 2011b). In the same year, the Committee for Examining Electricity Costs in the National Project Staff of the Government (NPU) projected the damages to be compensated at 5.7 trillion JPY. It converted the related compensation cost to 40 times the nuclear power production of 2010 and assumed that a severe accident occurred only every 40 years or 2,160 NPR running years.[53] This led to additional costs of only 0.5 JPY/kWh (NPU 2011).

However, already by applying a retrospective SA probability of 0.2% and a then stock of 50 NPRs, additional costs of about 2 JPY/kWh arise. In order to estimate the total cost for decontamination, which had not or only slightly been taken into account in 2011, the model by Yukio Hayakawa can be used (Kamisawa 2011b, 417-9). This model assumes, that at least the area within a radius of 50 km around the Fukushima-1 NPP was exposed to a radioactive contamination of more than 1 µSv/h or 680,000 Bq/m^2 caesium 137 (= 3.14 × (50 km)^2/2 = 3,925 km^2) (Hayakawa 2011) and therefore must be decontaminated.[54] The decontamination of a rural settlement area costed about 3.6 billion JPY/km^2 in 2012.[55] Consequently, the

53 1 SA/54 NPRs × 40 running years = 1 SA/2,160 NPR running years = 0.05% probability in contrast to Japan's tracking record: 1 SA/1,494 NPR running years = 0.07% probability (counting 3/11 as one SA) or 1 SA/498 NPR running years = 0.2% probability (counting 3/11 as three, because the fuel cores of NPRs nos. 1, 2 and 3 at the Fukushima-1 NPP melted down).

54 This account applies to about half the area of the so-called Urgent Protective Action Planning Zone (UPZ) with a radius of 30 km around the damaged Fukushima-1 NPP, i.e. 1,413 km^2.

55 The following large-scale decontamination contracts became publicised by 2011 and 2012: Kawamata-chō: 62 ha/3.2 billion JPY, Tamura-shi: 33 ha/1.7 billion JPY, Hirano-chō: 114 ha/3.19 billion JPY, Fukushima City: 10 ha/1.5 billion JPY. This totals to 9.59 billion JPY for 2.19 km^2 or 4.4 billion JPY/km^2. In addition, decontamination costs for private houses were indicated at 0.75-0.88 million JPY/house (*The Asahi Shimbun*, 31 January 2012, 9). The decontamination costs for an area of 3,925 km^2 amount to 14.1 trillion JPY.[56] If one subtracts a decontamination budget of 1.1 billion JPY, which was already included in the AEC's and other official estimations, additional cost of 13 trillion JPY has to be considered. Due regard should be given to treatment and compensation costs for those who develop cancer or are born with genetic damage as a result of radioactive contamination over the next 10 to 50 years (Kodama 2011). An estimate of the consequences of the Fukushima multiple Maximum Credible Accident (MCA), based on the model used by the European Committee on Radiation Risk (ECRR),[57] leads to a total of 223,000 cancer cases over the next decade alone.[58] Assuming a non-lethal outcome for all these cases and applying the human capital method with a ten-year income loss as cost equivalent (Ewers, Rennings 1992), medium term illness-related costs amount to 11 trillion JPY.[59] Considering these officially ignored or underestimated additional costs of decontamination and illness treatment, the total amount of losses should be estimated at least at 30-35 billion JPY.[60]

city of Minami-Sōma decided on a large-scale decontamination of its inhabited urban area of 14 km^2 over two years at 40 billion JPY (*The Asahi Shimbun*, 2 February 2012, 38). With a population density of 166 persons/km^2 (as of January 2012) and an average household size of three persons, this meant 55 households/km^2 or 22,000 households in the area in question. If one assumes a single-family house rate of 80% and withdraws the approximately 6,000 destroyed houses, 11,600 residential buildings remain. With decontamination costs of 0.75-0.88 million JPY/house, the decontamination costs of all residential buildings in Minami-Sōma amount to 8.7-10.2 billion JPY, which have to be added to the decided budget of 40 billion JPY for large scale decontamination. This again results in decontamination costs of 48.7-50.2 billion JPY for the area of Minami-Sōma or an average of 3.6 billion JPY/km^2. These data included an adjustment of the average decontamination cost estimate to 3.6 billion JPY (= 58.3 billion JPY/16.2 km^2). A 2013 cost estimation by AIST for decontaminating 300 km^2 (at 5 cm soil replacement) results in 1.02 billion JPY/km^2 without storage cost and 4.6 billion JPY/km^2 with storage cost (AIST 2013).

56 Kamioka and Oka used Iidatemura's decontamination cost rate (7.1 billion JPY/km^2) and calculated the total national cost at 28 trillion JPY (Kamioka, Oka 2012, 193).

57 In contrast to the ICRP model, the ECRR model considers not only external but also internal radioactive exposure (Busby 2011a, 2; 2011b).

58 Over the 50 years after 3/11, the ECRR expects a further doubling of the number of cases (Busby 2011a, 10-11; ECRR 2010). Recent critical reviews of available data on thyroid cancer incidents in the Fukushima region lean on the results of the first screening round conducted from October 2011 to April 2015 and showing a thyroid cancer incident rate for both sexes of those who were 0-18 years old in 2011, which is 79.4 times higher than the respective nationwide data collected before 3/11 (Hiranuma 2017). Based on data from the first, second and third screenings, Tsuda identifies a significant increase in thyroid cancer incidents in the Fukushima region, even though 2,700 patients under observation (partly with already treated cancer or positive indications) had been excluded from the screening survey (Tsuda 2018).

59 11.15 billion JPY = 10 years × 5 million JPY/year and household × 223,000 cases of illness.

60 Considering the human (ICRP model) and material damages and calculating them at a discounting rate of 3% for capital cost, Park estimated the total economic loss, which would

In December 2016, METI came up with a new cost estimation and revised its previous one to 21.5 trillion JPY (8 trillion JPY for decommissioning, 7.9 trillion JPY for compensation, 4 trillion JPY for decontamination, and 1.6 trillion JPY for intermediate storage) (METI 2016a). Against the backdrop of the liberalization of Japan's electricity retail market (started in April 2016), the revision was not intended to admit previous downplaying of how expensive nuclear power actually is. It was aimed at backing the government's decision (made eleven days after the release of the new cost estimation) about how to cover these costs while protecting the NPP operators. At face value, 15.7 trillion JPY were to be paid by TEPCO drawing on future profits (but are actually financed by government bonds and guarantees amounting to a total of 13 trillion JPY) and future capital gains from converting preferred TEPCO shares at a conversion price of 30-300 JPY per share into standard shares and selling the latter at a higher price than the conversion price actually paid.[61] 1.6 trillion JPY for intermediate storage and 0.2 trillion JPY for decommissioning support were to be paid directly by the central government, 3.7 trillion JPY by all other former regional monopolies and NPP operators and 0.24 trillion JPY by 'new power companies' without NPR/NPP. But, actually, after 2020, 2.44 trillion JPY for increased compensation (consisting of 1.2 trillion JPY to be paid by TEPCO, 1.0 trillion JPY by the other former regional monopolies/NPP operators and 0.24 trillion JPY by the 'new power companies') will be shifted to all electricity consumers (including those of new electric power suppliers) in form of a surcharge for transmitting electricity through the networks owned by the NPP/NPR operators and former regional monopolies (Kakugi kettei 2016). This surcharge will amount to 600 billion JPY per annum over 40 years. In March 2017, the Japan Center for Economic Research (JCER) released a cost estimation of 49.3 trillion JPY, with decontamination of sea water release excluded and 70 trillion JPY with decontamination of sea water release included (11 or respectively 32 trillion JPY for decommissioning, 8 trillion JPY for damage compensation, 30 trillion JPY for decontamination). The costs of nuclear power add up to 14.7 JPY/kWh and are thus obviously higher than electricity generated in coal and LNG fired power plants at 12.3 JPY/kWh and 13.7 JPY/kWh, merely by doubling the capital cost of a current NPR of 370,000 JPY/kW (METI's low assumption of FY2014) to 740,000 JPY/kW and disregarding the price fall for fossil fuels from 2014 to 2016 (JCER 2017).

A probability of one SA occurring every 2,000/1,494/498 NPR running years (0.05/0.067/0.5%), a running NPR fleet stock of 50 NPRs and

occur in case of MCA at NPR no. 3 of the Ōi NPP in the much more densely populated Kansai region, at 62-279 trillion JPY (Park 2005).

61 However, assuming a conversion price of 300 JPY/share, the TEPCO stock price has to be 1,500 JPY (compared to the actual stock price of 450 JPY as of 18 April 2018) to realise the expected capital gain of 4 trillion JPY.

271.3 TW of electricity generated by all NPPs (FY2010) and an assumed total damage of 30-35 trillion JPY result in a risk premium of 2.76-3.23/3.70-4.32/11.10-12.95 JPY/kWh for nuclear power generated electricity to be added to the cost of capital and operating. Estimating the total damage at 40-70 trillion JPY, the risk premium of nuclear power generation amounts to 3.69-6.45/4.93-8.64/14.80-25.91 JPY/kWh respectively. Some say that it is inappropriate to base cost estimates on the retrospective occurrence rate of 0.5% (3 SA in 1,494 NPR running years). But this is not convincing, as NPPs cannot be made resistant against most powerful earthquakes.[62] Consequently, private insurance companies refuse to insure NPR/NPPs beyond the upper limit of 120 billion JPY (Shinagawa 2011). This threshold demonstrates the dubiousness of SA probabilities that proponents of nuclear power assume in their cost estimations at a rate lower than the tracking record of one SA per every 498 or 1,494 NPR running years (tab. 3.2d).

Table 3.2d Projections of nuclear power costs for SA-related damages and compensation

Running NPR stock of 50 NPR, 271.27 TWh of electricity by NPR/year (FY 2010)	Losses of 21.5 trillion JPY (METI 2016)	Losses of 30-35 trillion JPY	Losses of 40-70 trillion JPY (JCER 2017)
3 SA/1,494 or 1 SA/498 NPR operating years = probability 0.5% (tracking record of Japan)	7.96 JPY/kWh	11.10-12.95 JPY/kWh	14.80-25.91 JPY/kWh
1 SA/1,494 NPR operating years = probability 0.067% (tracking record of Japan)	2.65 JPY/kWh	3.70-4.32 JPY/kWh	4.93-8.64 JPY/kWh
1 SA/2,000 NPR operating years = probability 0.05% (assumption by METI)	1.98 JPY/kWh	2.76-3.23 JPY/kWh	3.69-6.45 JPY/kWh
1 SA/10,000 NPR operating years = probability 0.01% (target by IAEA, NCR)	0.40 JPY/kWh	0.55-0.65 JPY/kWh	0.74-1.29 JPY/kWh

Source: Compiled by Author

Thus, the costs of nuclear power generation are by no means the lowest. Considering realistic utilization rates and operating lifespans as well as discounting rates and largely socialised costs, such as back-end, state subsidies for settlement, R&D programmes, risk premiums or compensation – insofar as they are calculable and can be fully taken into account – nuclear power generation is to be acknowledged as most expensive.

62 For earthquakes with a magnitude of more than 8, gravitational accelerations of up to 1,000 GAL occur vertically and horizontally. Complex industrial plants cannot be made resistant against such earthquakes, because gravitational pull may exceed 980 GAL (Hirose Takashi 2010, A15).

3.3.4 Liberalising Japan’s Electricity Market: Making Nuclear Power a Defensive Wall

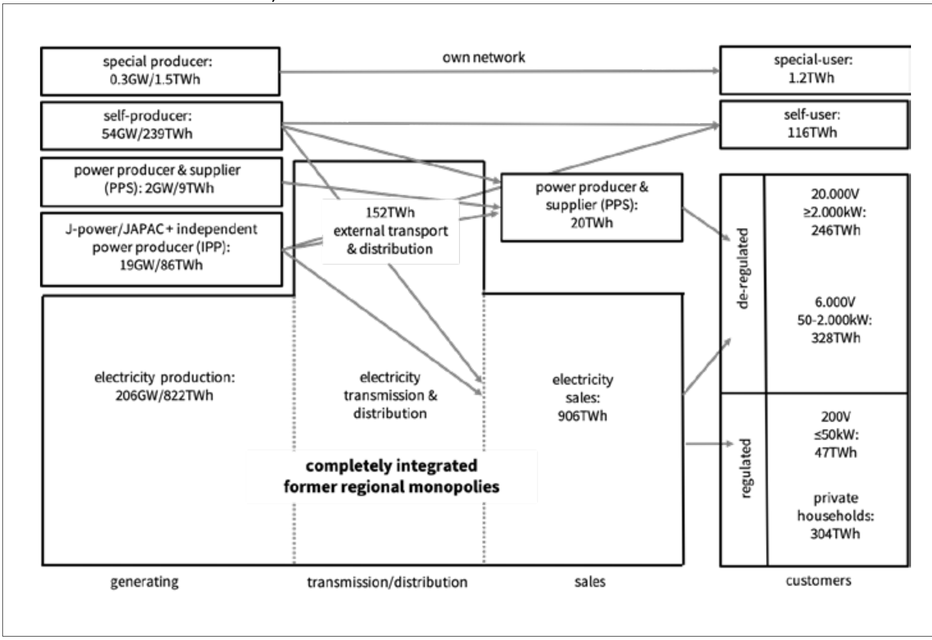
In the early ’90s, Japan’s attempt to meet the return requirements of accumulated capital through lowering interest rates and boosting asset inflation, leverage and related consumption failed. To prevent a systemic implosion, the state emerged as debtor and demand-generating investor. Capital owners and creditors wrote off losses, companies reduced their liabilities and costs. As a result, Japan’s economy has been in a so-called deflationary crisis. In the mid-’90s, when hope for quick fixes faded, the neoliberal triad of deregulation, privatisation and welfare cuts gained popularity. In this context, calls to liberalise also the electricity market after rail traffic and telecommunications and to break up regional monopolies became louder. Hopes for lower electricity prices to result from free competition arose. Decentralised and cost-effective technologies such as heat and power co-generation and micro gas turbines were expected by experts to spread faster, a more flexible supply control (Kumamoto 2011, 20-1) and demand-driven investment behaviour were anticipated to replace political interventions as well as the non-transparent approval process for electricity cost prices and capacity building (Anayama 2005, 193-4). The regional monopolists argued that only a vertically integrated, centralised system of generation and transmission as well as economies of scale based on large-scale technology would enable a stable and cost-effective supply. Liberalization was also feared to set off a reckless race for the lowest price and to allow speculative exploitation of discrepancies between supply and demand. The power crisis in California and the bankruptcy of Enron in 2001 seemed to confirm these reservations against deregulation.[63]

The first retail market segment for ultra-high voltage users (large scale factories, department stores and buildings) was liberalised in March 2000, followed by another one for small and medium scale factories and buildings, which was opened for so-called Power Producers and Suppliers (PPS) in March 2005. In March 2016, the last remaining segment, the one for low voltage users, i.e. private households and small retailers, was liberalised. As of April 2018 electricity can be purchased from 468 registered electricity retail suppliers, depending on their respective regional coverage zone. Existing standard price schemes will remain unchanged until 2020, while new and special price menus can be freely set.

In response, former regional monopolists and NPP operators concentrated their resistance on preventing the neutralisation of onward and outward electricity flows, that is, equal access for all suppliers to the electricity grid. As a matter of fact, they have succeeded in introducing expensive transmitting

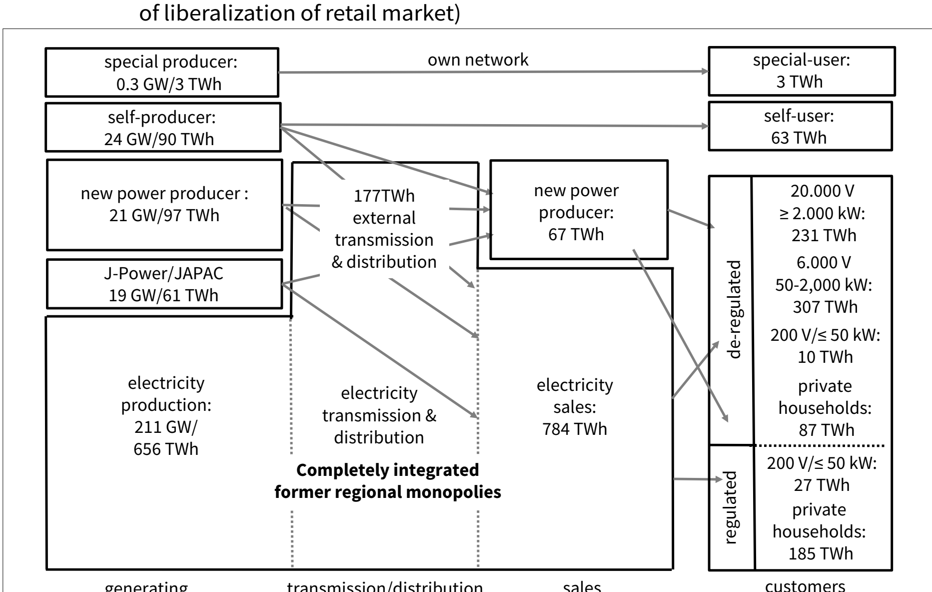
63 Mitsuharu Itō 2011b, 174-5; Kikkawa 2011, 145-6; Hiroshi Takahashi 2011, 156-68.

Figure 3.6a Structure of the electricity market in Japan as of FY2010 (before retail liberalization)



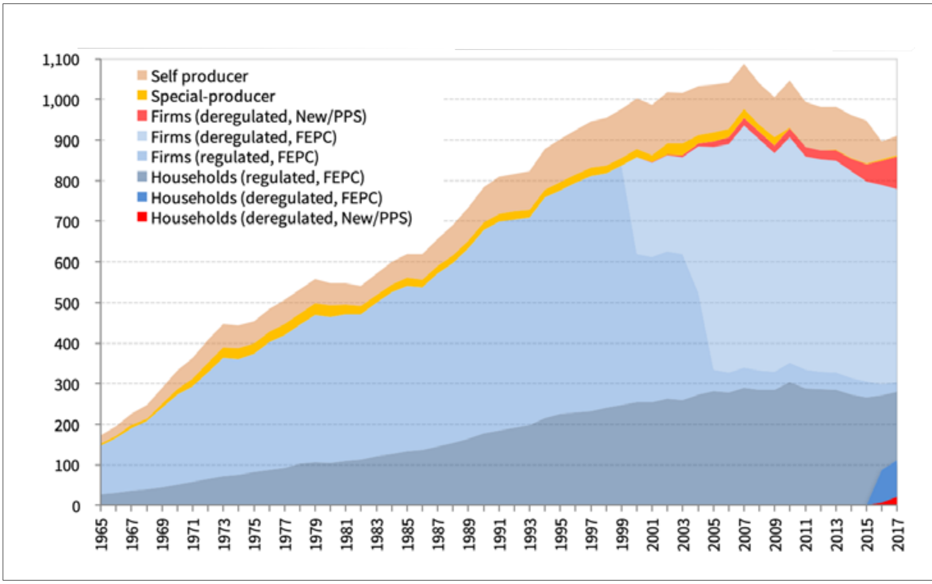
Source: Author, based on METI 2018b

Figure 3.6b Structure of the electricity market in Japan as of FY2016 (after start of liberalization of retail market)



Source: Author, based on METI 2018b

Chart 3.19 Electricity demand by provider and customer groups and state of regulation in Japan (including self-production and self-user, TWh/a, FY)



Source: Author, based on JBHI 2018; FEPC 2018; METI 2018b

and imbalance fees (Kumamoto 2011, 48-53). Thus, the impact of liberalization on Japan's electricity market structure was actually limited with regard to change in market shares (figs. 3.6a-b). Theoretically, independent electricity producers (the so-called PPS) have been allowed to serve the entire high-voltage segment (from 6,000 V/50 kW) since 2005, which represented more than 60% of the total electricity demand. But they are charged tremendously high fees by the regional monopolists for the transmission in the ultra-high (over 2,000 kW/20,000 V) and high-voltage segment (50-2,000 kW/6,000 V), ranging between 2.59-5.19 JPY/kWh in 2004, 1.88-3.47 JPY/kWh in 2010, 1.62-5.20 JPY/kWh in 2015/16. PPSs also have to pay a maximum of 48 JPY/kWh (three times the standard cost price) as compensation for any gap between actual electricity supply and demand over 3% that they cannot balance within 30 minutes (as of 2008-2016) (Kumamoto 2011, 51).[64]

The market share of the so-called new electricity producers (or former PPS) in the price-sensitive ultra-high and high voltage segments has grown from

64 The big electric power companies charge all other sellers not only shortage but also surplus (both from 3% upwards) in addition to the standard cost price. As of 2016, these balancing charges amount to an national average of 14.3 JPY/kWh and a maximum of 21.82 JPY/kWh (METI 2017d).

5.2% in FY2014 to 7.6% in FY2015 and 10.9% in FY2016 to remarkable 14.7% in FY2017 (METI 2018b). But the former regional monopolies are losing market share only slowly; they are still dominating the market (chart 3.19).

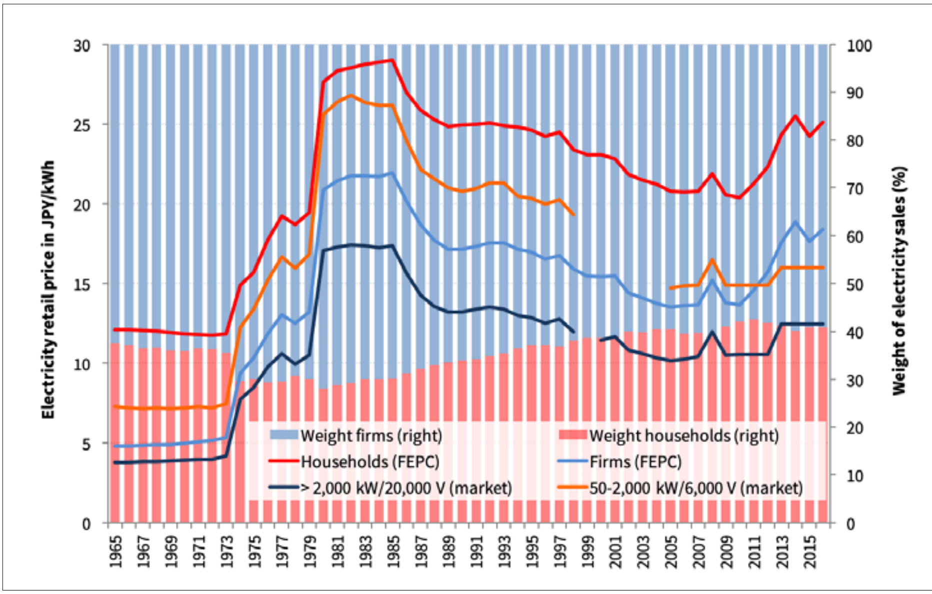
The former regional monopolies and NPP operators have been able to protect their dominant position particularly in the high margin low-voltage segment. Here, the new entrants' market share reached 2.6% in FY2016 (the first year of liberalization) and has – though remaining still single-digit – grown to 6.9% in FY2017. This is mainly due to prohibitively expensive transmitting fees of 7.81-9.93 JPY/kWh (as of 2015 and 2016 respectively), which the owners of the grid charge to the electricity sellers. These charges represent 31-36% of the electricity retail price for low voltage/private households (25 JPY/kWh as of FY2016). Finally, the private households are to pay the relatively high margin of the big electric power companies and subsidise the lower margin as well as the relatively cheap purchasing price of large corporate electricity consumers: although the share of private households among the total electricity sold by the big electric power companies is only 33.6% (as of FY2016), the big electric power companies generate 40.8% of their sales turnover from selling electricity to them (chart 3.20a).

Dividing the shares of total electricity sales turnover by the shares of electricity consumption of firms and private households reveals that the degree of privileging the corporate sector has not changed since the early '80s, despite all partial measures of liberalization. On the contrary, compared with 1980, it had even slightly increased until the 'liberalization' of the low voltage/private household segment in FY2016 (chart 3.20b).

Before April 2016 private households could not freely choose their electricity provider and therefore had to pay the electricity retail prices of the regional monopolists. In turn, the latter offered large corporate users electricity as cheaply as possible in the already deregulated market segment, which represented two thirds of the total electricity consumption.[65] The regulated electricity price, applied to the then regulated low voltage market segments

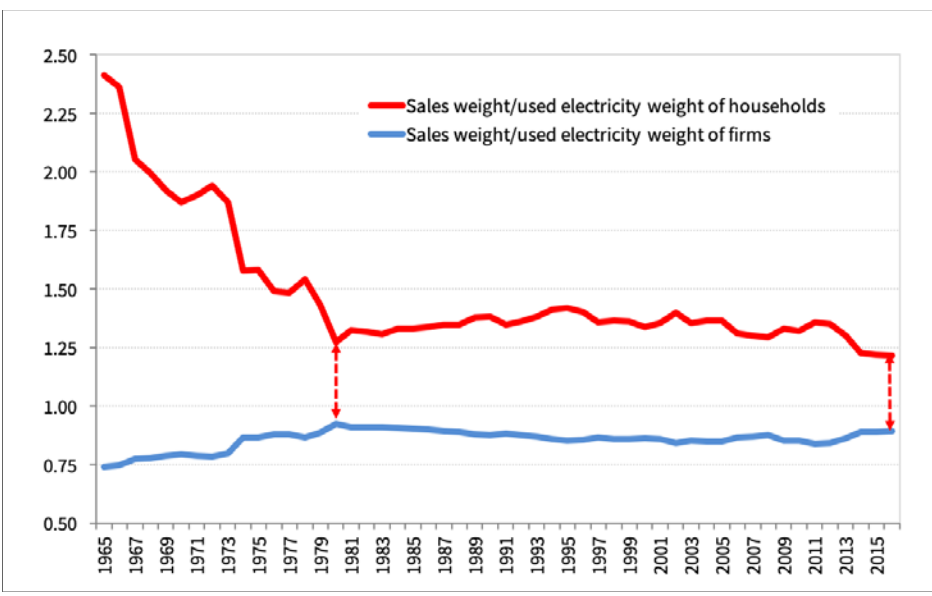
65 Before the partial liberalization a hidden cross-subsidisation (violating the principles of total cost approach, reasonable profit and equal treatment of customers) was supposed to be prevented by the allocation of costs and electricity consumption to each user segment in the process determination of the electricity price. Different supply costs, demand or load patterns and shares of customer costs of the respective power consumption are relatively easy to determine. In addition, it is important how much of the fixed costs of electricity generation and transmitting are attributed to which user segment. High in total, these costs are to be borne by all, although they are not specified according to user group. Their allocation has been based on the share of the respective demand group in the maximum power output during the annual peak load day, the annual consumption amount and the peak load in the ratio of 2:1:1 (Anayama 2005, 51-5, 93-8, 196). Liberalization was intended to prevent cross-subsidisation of the deregulated by the regulated sector within an electricity company through controlling the annual revenues and expenditures in the respective segments (Anayama 2005, 198; Ōshima 2010, 63). But such controls have been depending on the financial reports by the electric power companies themselves, which used special

Chart 3.20a Electricity retail prices and sales by firms and households (FY)



Source: Author, based on FEC 2018; METI 2018b

Chart 3.20b Electricity sales weight and electricity consumption weight of private households and firms in Japan (FY)



Source: Author, based on METI 2018b

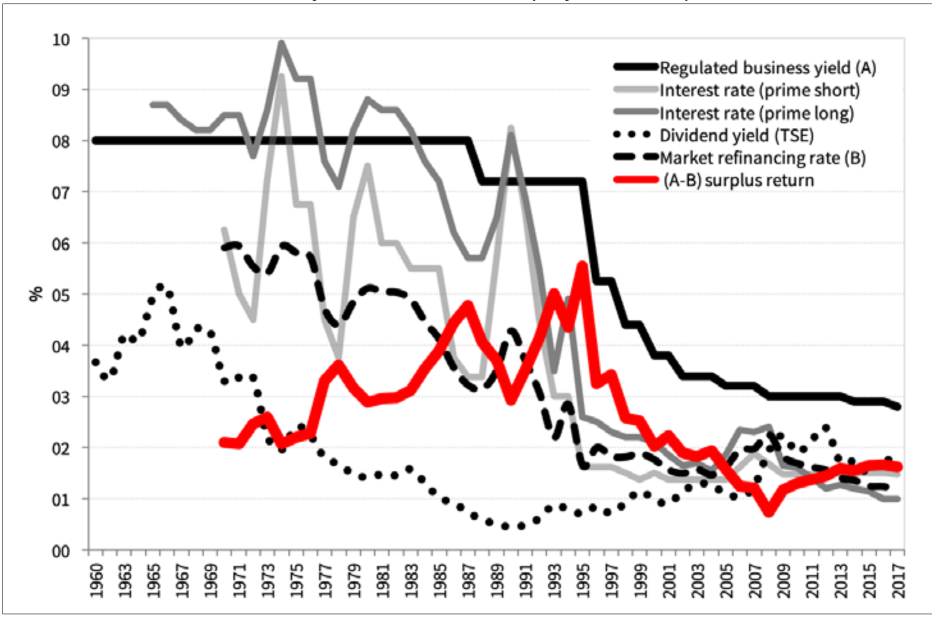
and scheduled to be abandoned in April 2020, has been calculated as the sum of the current operating costs (including fuel and depreciation) and reasonable interest on the assets required or used in the electricity business (facilities in operation and under construction, nuclear fuel rods or fuel stocks, investments in raw material development, R&D expenditures and 1.5 monthly working capital). This sum is divided by the amount of electricity generated. Thus, the regional monopolists have been exempted from short- and medium-term refinancing risks. Furthermore, the regulated return on business (*jigyō hōshū*)[66] has exceeded the market average of refinancing costs for external (loans) and internal (equity) capital in a range of 1-4%, allowing the regional monopolists to pay the difference to their shareholders as increased dividend or to retain these 'regulated margins' as profits, as long as actual refinancing costs are close to or lower than the market rate (chart 3.21).

Under these conditions, regional monopolists have been inclined to expand their generation capacity and invest into large-scale power plants as well as generation technologies. Once these capacities were built, the companies tried to achieve economies of scale by offering and selling to large customers as much electricity as possible at low prices. However, these capacities are inflexible, which remains without financial consequences as long as the additional costs of equalizing the difference between basic and peak load can be absorbed by the relatively high electricity prices in the regulated sector (i.e. private households). If regional monopolists have to cope with set prices but are guaranteed the integration of the costs for running and refinancing their assets into the regulated price, they will primarily seek to increase their asset volume, sales turnover and absolute profit amount through borrowing, as long as the interest and dividends do not exceed the regulated return on business. The trend of main financial indicators at the large electric power companies from 1970 to 1999 (chart 3.22a) confirms this: apart from price increases during the oil crises of 1973 and 1979 and the subsequent reduction in fuel costs due to the appreciation of the JPY, the regional monopolists boosted their total asset volume faster than the sales turnover through finan-

accounting rules (e.g. excluding NPP-related capital provisions and externalising these costs) (Kanamori 2016, 1148-50).

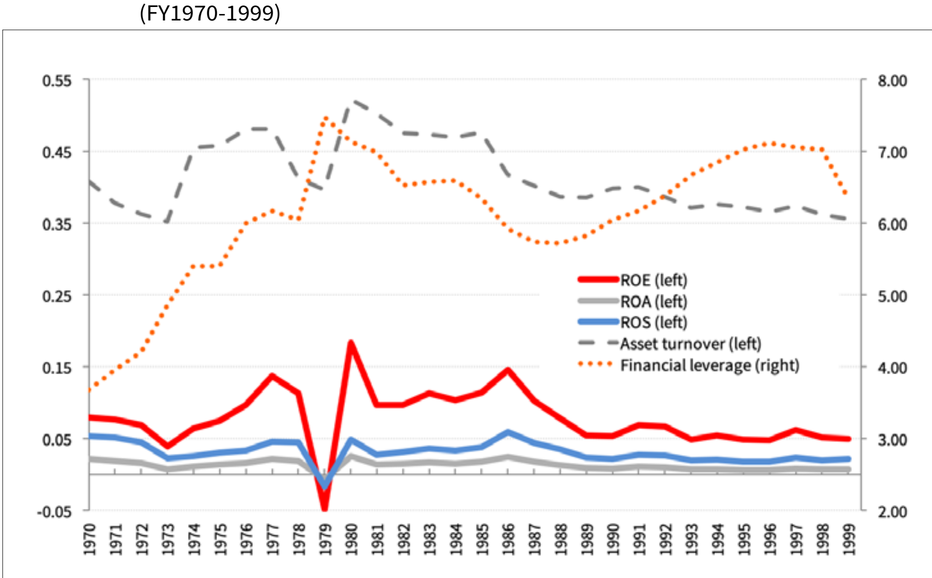
66 Actually, in the cost calculations for FY2013-2016, approved by METI, the so-called return on business is higher (at an average of around 5%) than the officially indicated and regulated return rate of 2.8-2.9% as it includes the actual refinancing costs. Before 3/11 electric power companies as regional monopolists were supposed to be low-risk or almost risk-free borrowers and therefore able to raise external capital at relatively low cost. Consequently, the refinancing costs of their total amount of liabilities are still relatively low (at around 1%). And electric power companies are still rated as highly credible (A) except TEPCO (BBB), issuing 5/10/20-year corporate bonds at a nominal interest rate of clearly less than l% per annum. However, refinancing costs are set and approved by METI as an element of the regulated electricity price at a higher rate and added to the indicated regulated return rate on business.

Chart 3.21 Regulated business yeld (A), market-based refinance rate (B), average interest rate and dividend yield (until 1995: 50 equity/50 debt, up from 1996: 30/70)



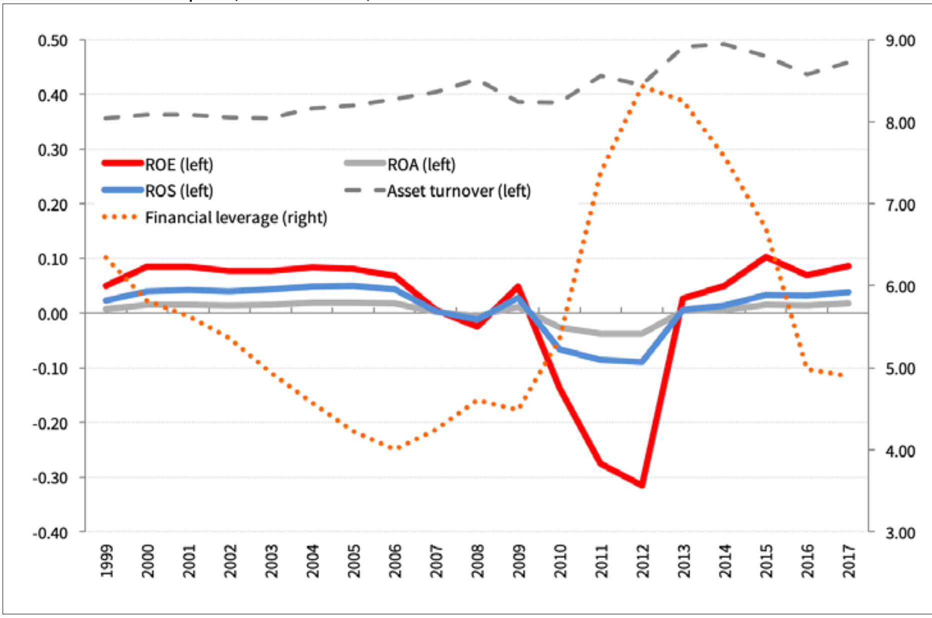
Source: Author, based on BOJ 2018; JPX 2018; METI 2018

Chart 3.22a ROE drivers for FEPC-member firms (regional monopolies) in Japan (FY1970-1999)



Source: Author, based on FEPC 2018, IR-Reports

Chart 3.22b ROE-drivers for FEPC-member firms (regional monopolies) in Japan (FY1999-2017)

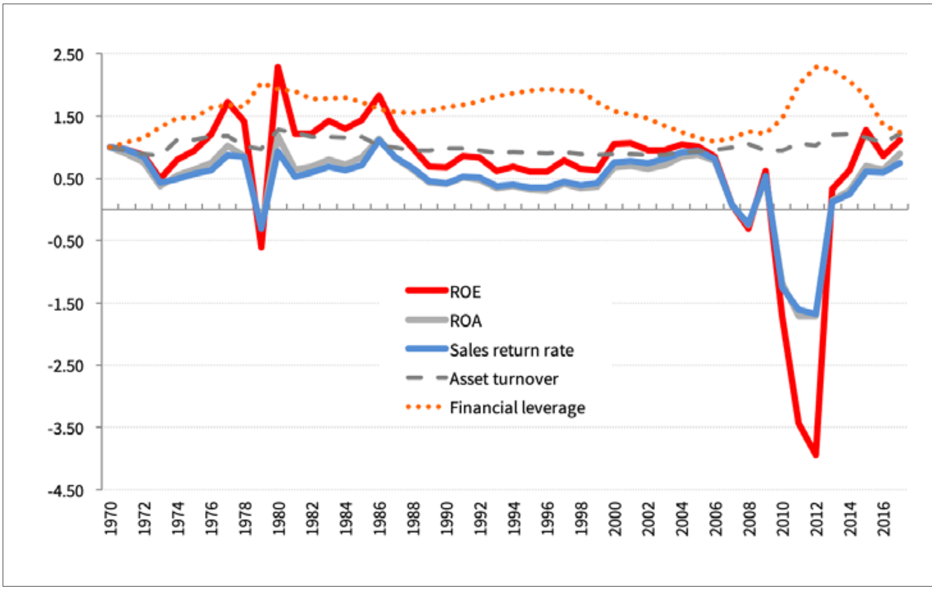


Source: Author, based on FEPC 2018, IR-Reports

cial leverage, which is why the asset turnover rate has dropped.[67] However, if regional monopolists are exposed to competition in supply and price within a stagnant market, they will have to lower their prices and costs to avoid losing market share. They will reduce capacity investment and financial leverage, making better use of their fixed assets. The trend of financial data from 2000 onwards (charts 3.22b-c) indicates exactly this: leverage fell until 2006, while the total volume of assets increased only slightly. Besides the financial crisis, the slump in sales, net assets and return on equity in 2008 is attributable also to the fact, that the rise of the oil price in a partially deregulated market could not anymore be absorbed easily by a general raise of the electricity prices. Passing on these additional costs almost entirely to customers in the regulated market segment could have triggered demands for extending market liberalization to the private household segment.

67 The return on equity (ROE) can be calculated as the product of return on assets (ROA; how much profit was generated from investing into and utilising assets?) and financial leverage (how much are assets refinanced with debt?): ROE = ROA × leverage. Further, ROA can be broken down into the return on sales (ROS; how much profit was generated from sales?) and the asset turnover rate (ATR; how much sales was generated from utilising assets?). Therefore, profit/equity (ROE) = profit/sales (ROS) × sales/assets (ATR) × assets/equity (leverage). It is now possible to determine which of the factors affects the return on equity to what degree.

Chart 3.22c ROE-Drivers for FEPC-member firms (regional monopolies) in Japan (1970 = 1, FY)



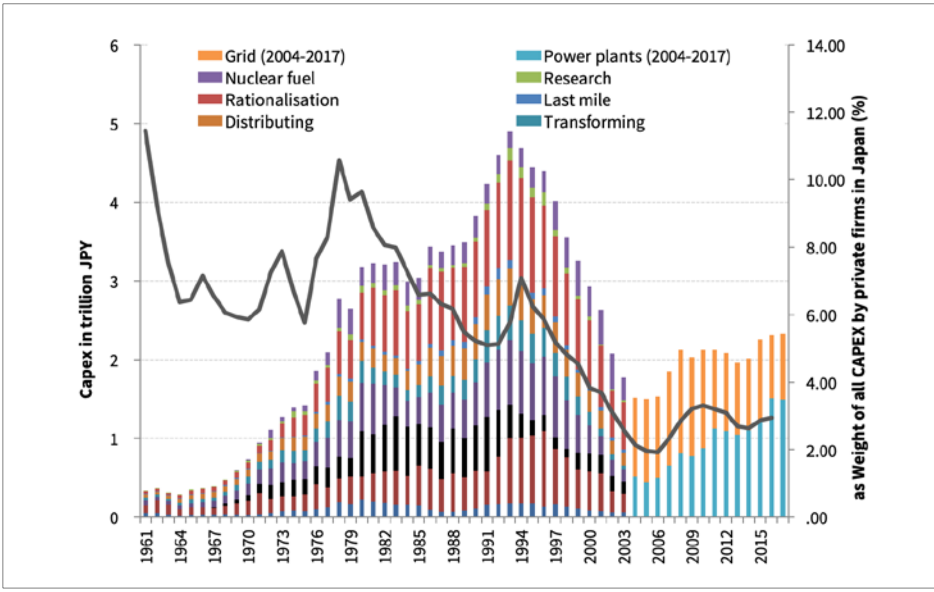
Source: Author, based on FEPC (2018), IR-Reports

This would have been incompatible with the capital-intensive maintenance and expansion of the NPP fleet. Furthermore, it does neither suit the interests of government and bureaucracy, whose industrial scheme of keeping nuclear technology and fuel stock as political option and power tool would have been jeopardised by market liberalization. Encouraged by the Nuclear Renaissance in the US, it was decided in 2004-2005 to halt market liberalization and prioritize nuclear power generation in Japan's energy and industrial policy (Kikkawa 2011, 146-9).[68] As a result, the regional monopolists did not only defend their dominant market position, but also attempted to make themselves less vulnerable. Eventually, they managed to keep the power grids under their control and erect barriers against new entrants (Yoshimatsu 2011, 288-95). The government's commitment to the nuclear cause was reason enough for the regional monopolists to slightly increase capital investment again until 3/11 (chart 3.23).

However, to avoid further demands for market liberalization, internal pressure on the operational cost at electric power companies was kept high. This had particularly dangerous consequences for NPPs: lifespan

68 See also § 3.2.3 in this chapter.

Chart 3.23 Capital expenditures (CAPEX) of FEPC-member firms (FY)

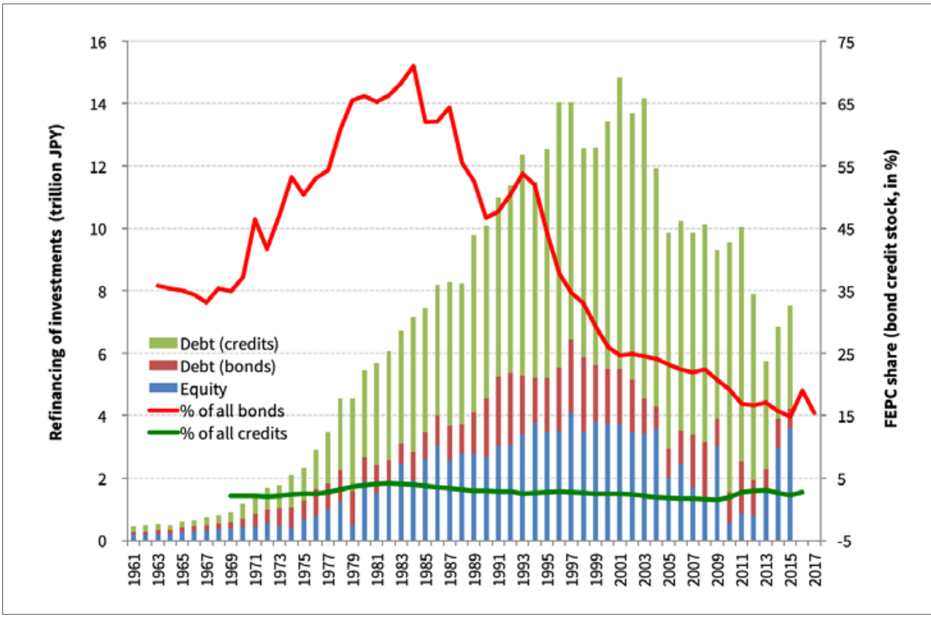


Source: Author, based on JBHI 2018; FEPC 2018; CAO 2018a

and operating intervals of older NPRs were extended and – as in the case of the damaged Fukushima-1 NPP – safety-related but costly conversions and retrofits were voided or delayed (*The Asahi Shimbun*, 6 April 2011, 2).[69] Japan's government as well as the electric power industry could rely on the strong support from large corporations, main industries and their lobbying organisations: in the first half of the '80s, fixed investment in the electricity industry accounted for more than 7% of all investments made by Japanese private companies. Although their share had fallen to below 3% in the early 2000s, electricity companies are more important customers than ever before in the face of declining public investment and business for the heavy, plant and construction industries (chart 3.24).

69 In its ruling of 17 March 2017, the regional court of Maebashi confirmed that in May 2008 TEPCO was aware of the relatively high occurrence probality of a M8 earthquake, estimated at 20% in the coming 20 years and at 30% in the coming 30 years, as well as the danger of tsunamis, caused by such an earthquake and putting vital safety facilities like emergency power generators out of function. But even though, TEPCO did not take necessary counter measures in order to avoid additional costs and further screenings by regulation authorities (Nobuaki Takahashi 2017b, 456).

Chart 3.24 Refinancing of investments by FEPC-firms (flow) and FEPC-firms share of corporate bonds and credits in Japan (Stock) (FY except 2017)

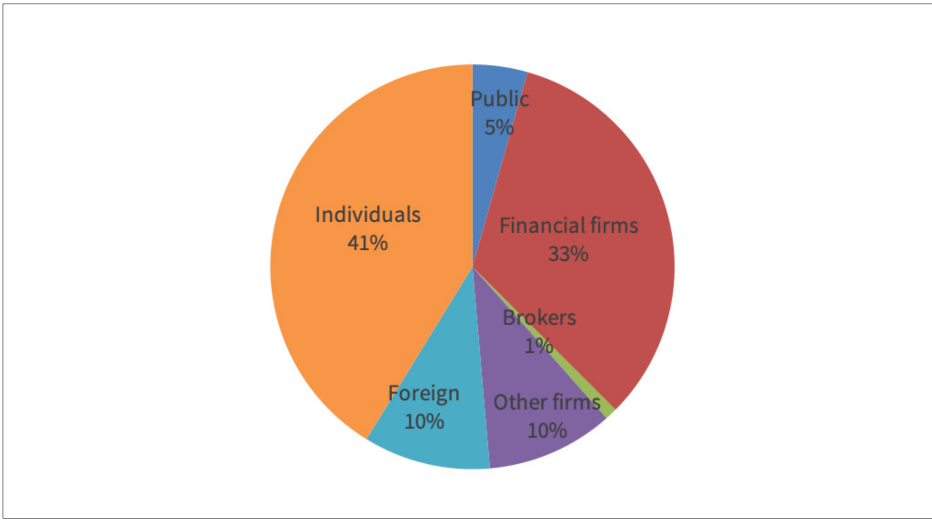


Source: Author, based on JBHI 2018; BOJ 2018; JSDA 2018; FEPC 2018

The electric power companies have been extremely important customers also for the financial industry: valued as low risk debtors (before 3/11: AA+) with huge refinancing demand due to their untouchable position as regional monopolies, stable cash inflows and major capital investments, the electricity companies have been raising external capital not only in the form of loans, but also through issuing long-term bonds. In the late '70s and early '80s the latter accounted for two thirds, as of March 2017 for about 20% of all outstanding corporate bonds (including short-term redemptions) issued by Japanese private companies apart from the financial industry. Outstanding long- and short-term loans, accounted as liabilities in the balance sheets of the large electric power companies, represent 3% of all outstanding corporate loans provided by Japanese banks (as of March 2017). Thus, the single amount of credits given by Japanese banks to each of the large electric power companies is so big and the related credit risk so concentrated that lenders have a strong interest in avoiding a default of these debtors – writing-offs would be huge and affect the financial health of the lender immediately (chart 3.24).

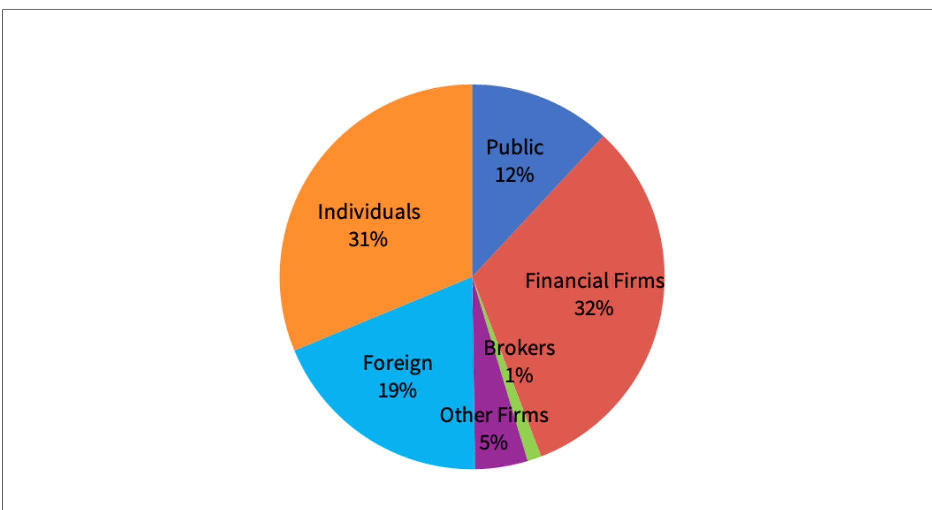
Before 3/11, the shareholder structure of the large electric power companies and NPP operators was characterised by two investor groups: individuals and financial institutions (chart 3.25a). Shares in electricity companies were considered to be defensive or counter-cyclical stock investments because of their relatively high dividend yield (compared to the low return on savings deposits) and the stable earnings situation (due to the lack of price competition). Financial institutions and large corporations had the blocking minority with more than one third of the voting shares (43% as of March 2011), while the high proportion of individuals with small holdings and the fragmentation of their total holdings had left the top executives of power companies with a relatively large amount of discretional scope as long as the interests of METI, ruling politicians and bureaucrats were met. After 3/11, financial institutions maintained their share, whereas public and foreign investors raised their respective weights, in contrast to domestic individuals and other firms, who reduced theirs. As a result, domestic financial institutions and public investors (mainly the central government through its 55% stake in TEPCO and some municipalities such as Tōkyō and Ōsaka) hold controlling stake of 44% in the stock-market listed big electric power companies and NPP operators (chart 3.25b). The commitment by the central government and METI to TEPCO – their ongoing financial and administrative support and promotion of nuclear power – has reduced the risk for domestic institutional investors considerably and provided risk-tolerant foreign institutional investors (hedge funds) with an opportunity to realise big capital gains by taking a long position (buying based on the expectation that the value of their stock holdings will rise).

Chart 3.25a Shares in 10 regional monopolies by investors as of 31 March 2011 (weighted with market capitalisation as of February 2012)



Source: Author, based on IR-Reports

Chart 3.25b Shares in 10 regional monopolies by investors as of 31 March 2018 (market capitalisation weighted as of April 2018, government's holding of preferred TEPCO stocks included)



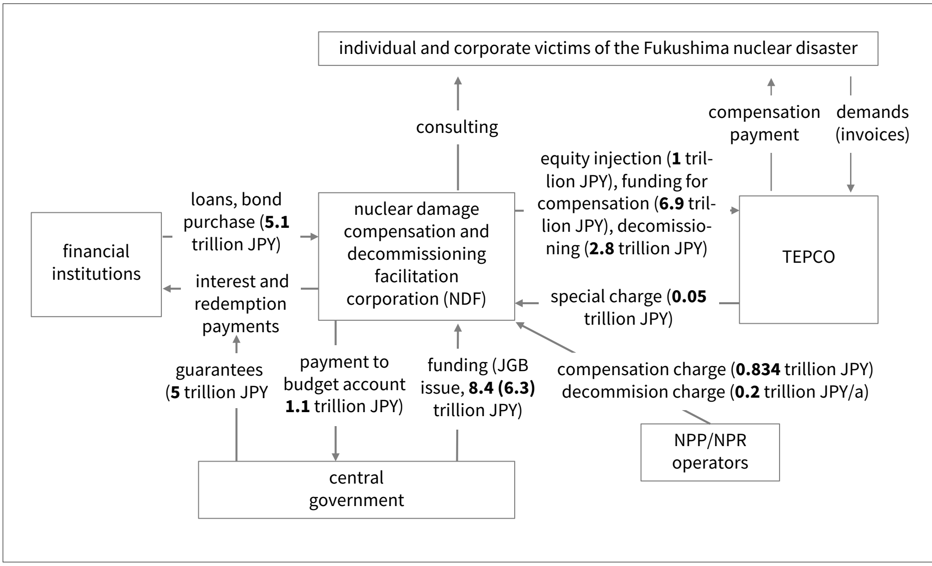
Source: Author, based on IR-Reports

Another factor for the ongoing commitment to NPP operators like TEPCO is their interdependency with Japan's financial industry. While being the main shareholder besides individuals, Japan's financial industry has been highly exposed to the heavily leveraged regional monopolies and NPP operators as lender. On the other side, the NPP/NPR business with its huge amount of fixed cost and fixed assets has been relying on the financial industry for stable and low-cost funding. Japan's government provided huge public funds to rescue both TEPCO and the financial industry. There are (a) government guarantees for the bonds issued to raise capital for compensation payments and decommissioning by the Nuclear Damage Compensation and Decommissioning Facilitation Corporation (NDF) (13.5 trillion JPY planned, 1.4 trillion JPY issued by June 2018), (b) government guarantees for loans from private banks for compensation payments and decommissioning by NDF (3.7 trillion JPY called by June 2018), (c) equity capital injection/underwriting TEPCO shares (1 trillion JPY), (d) subsidies for decommissioning and public funding of intermediate storage (2 trillion JPY), (e) a raise of the regulated electricity price by 8.5% in 2012 alone and another 16% until 2014 and additional transmitting charges (2.4 trillion JPY). While the government provides such tremendous public, NPP operators[70] take less burden. They have to pay 0.834 trillion JPY (among them 0.294 trillion JPY by TEPCO) as general burden charge (shifted to electricity consumers through price surcharge) to NDF. TEPCO pays 0.05 trillion JPY from operating income as special burden charge to NDF. And all NPP operators pay annually about 0.2 trillion JPY from decommissioning provisions, also originally charged by the electric power companies to the electricity consumers. Finally, Japan's government has allocated about 13 trillion JPY and raised 11.4 trillion JPY (as of the end of FY2016) to provide TEPCO with funds to pay its liabilities related to 3/11 damage compensation, decontamination and decommissioning (fig. 3.7).

Initially, the government had planned to redeem the outstanding public funds of expected 9.1 trillion JPY over the 25 years from 2015-2039, by paying interest of 1.0 trillion JPY out of its general budget, taking 4.4 billion JPY from electricity price surcharges and 1.3 trillion JPY from TEPCO future profits and realising 2.5 trillion JPY from expected capital gains of selling TEPCO shares purchased on loan and held by NDF. Following this projection, TEPCO shareholders would have to bear 14%, while taxpayers and electricity consumers would have to shoulder 11% and 48% respectively (Saitō 2015, 36-41). But by the end of 2016, the government had to admit that assuming 11 trillion JPY as total cost does not hold and that instead a funding of at least 21.5 trillion JPY is necessary (see $ 3.3.4). This sum was supposed to be covered by 1.6 trillion JPY from the general

70 10 FEPC member firms plus JAPC and JNFL.

Figure 3.7 Refinancing scheme of 3/11 damage compensation, costs of decommissioning and decontamination (accumulated as of end of FY2016)



Source: Author, based on METI 2016d; Saitō 2015, 26-41

budget, 7.8 trillion JPY from electricity price surcharges (over 40 years), 8.1 trillion JPY from future TEPCO profits (over 30 years) and 4 trillion JPY from expected capital gains of selling TEPCO shares (Kakugi kettei 2016; METI 2016b).

The principle of ownership responsibility would have called for TEPCO's insolvency and delisting, thereby reducing shareholder capital to zero.[71] As in other insolvency cases of large public corporations, for example Japan

71 As of the end of March 2010, TEPCO's shareholder capital was indicated at 2.5 trillion JPY. By March 2011, TEPCO's liabilities (amounting to 23.2 trillion JPY = 13.2 trillion JPY of bonds, loan and others plus 10 trillion JPY, consisting of the then estimated cost for decommissioning of 5 trillion JPY and for damage compensation of 5 trillion JPY) had exceeded its total assets of 14.8 trillion JPY by 8.4 trillion JPY (Saitō 2015, 20-5). Under the assumption that a company can survive with negative equity as far as its cash flows are sufficient to serve all current demands, and even in consideration of a rich operating cash flow of 832 billion JPY and operating profits of 192 billion JPY (both annual average FY 2006-2010), a negative equity, amounting to 8.4 trillion JPY or 57% of total assets, could have been hardly ignored by banks in their decision on new loans for TEPCO, because the past cash flows had been inevitably linked with the highly leveraged balance sheet, in other words, with permanent refinancing and redemption of existent loans and bonds. Banks remained reluctant about providing new loans to TEPCO directly, despite government guarantees for new funding through NDF, which has been keeping TEPCO solvent and the banks demands alive (Saitō 2015, 312-8).

Airlines (JAL), lenders and bond holders, too, would have been forced to write-off their demands, which amounted to 6.7 trillion JPY as of March 2010 (Saitō 2015, 318-23; Nobuaki Takahashi 2017a, 274). Then, TEPCO's assets (valued at 6.7 trillion JPY as of 31 March 2011) could have been used to refinance at least partly the NPR decommissioning, decontamination and compensation of damages incurred by 3/11 and estimated at 22-70 trillion JPY at least in part.

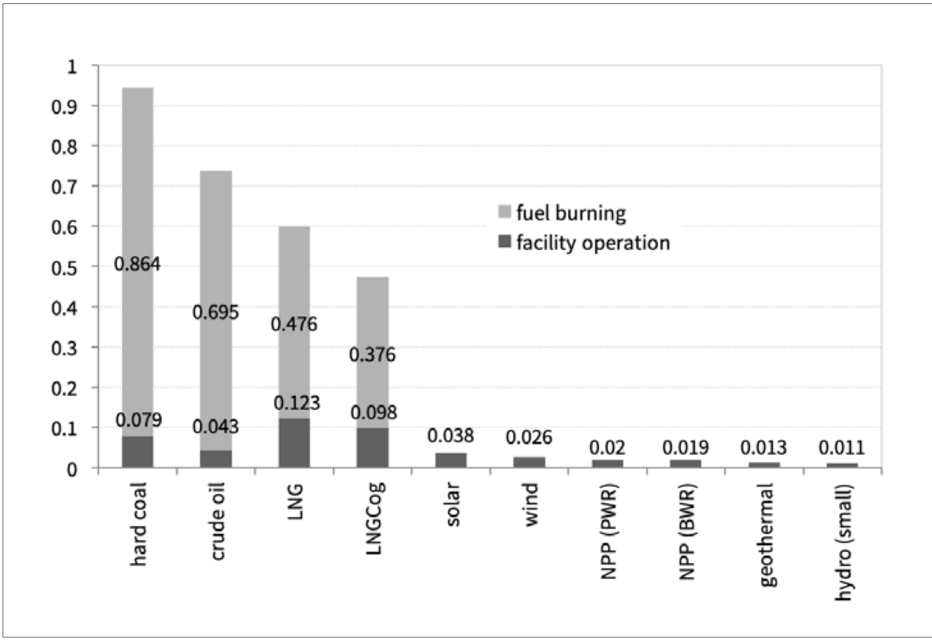
As Koga (2017) has pointed out, by keeping TEPCO alive through injecting huge public funds, METI was able to protect its position and its control of public budgets against harsh criticism and calls for an independent regulation of NPP-related businesses. Furthermore, METI has established a precedential case and administrative scheme for rescuing NPP operators, assuring them, their investors and debtors, that almost all risks will be minimised at the expense of taxpayers, non-NPP competitors and electricity consumers (Koga 2017, 356). In addition, Japanese experts expect METI – following the UK model – to introduce a Feed-in-Tariff (FIT) for NPR/NPPs to be paid by all electricity consumers and/or taxpayers (Ōshima 2014, 154-61; Hiroshi Takahashi 2017, 149-51). This would allow NPP operators not only to keep running, but to replace or even enlarge the existing fleet. NPPs could be re-established as a source of extra rent and the foothold of a centralised electric power system. Nuclear power generation would serve as a bulwark against further market liberalization and decentralisation.

3.3.5 Nuclear Power as a Rescue from Global Warming?

Japan's government, the electric power corporations and their pundits in mass media and academia have claimed that NPPs cause little or no CO_2 emissions (chart 3.26) and, therefore, are not only indispensable, but central to a sustainable energy policy.[72] Section 3.3.2 demonstrated how much energy is spent and how many natural resources are needed to produce and store nuclear fuel for NPPs. Experts agree that the CO_2 emission level

72 A current example is the proposal for the Fifth General Energy Plan by a METI sub-committee from 27 April 2018, affirming METI's earlier projection of Japan's energy mix in 2030 (METI 2015c) and arguing once more that the indicated 20-22% share of NPP in electricity generation (1,065 TWh/a) is needed in 2030 to fulfill Japan's commitment to the reduction of emissions that cause global warming, by 26% until 2030 and by 80% until 2050 (both compared to 2013) (METI 2018e, 3). Following this proposal, the 5th General Energy Plan was approved by the government on 3 July 2018. Further restarts of NPPs and the increase of nuclear power generation share from 1% in FY2013 to 20-22% in FY 2030 were declared as projective goal in order to raise the share of zero emission power generation from 12% in FY2013 and 16% in FY2016 to 44% in FY2030 and Japan's energy self-sufficiency rate from 20% in FY2010, 6% in FY 2013 and 8% in FY2016 to 24% in FY2030 (METI 2018g, 4, 10, 12).

Chart 3.26 CO_2 emissions in power generation by source of energy or plant type in Japan (by CRIEPI as of 2009, kg/kWh)



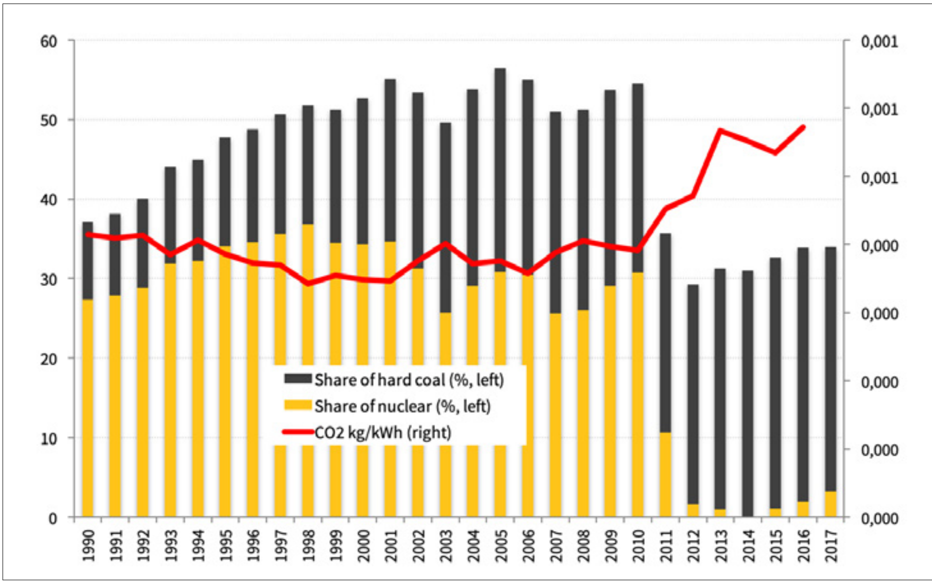
Source: Author, based on Imamura et al. 2016

of nuclear power significantly increases if calculations include emissions caused by interim and final storage of nuclear fuel and contaminated materials (Koide 2011b, 199).[73] Besides, NPPs achieve an energy efficiency of only one third, since two thirds of the energy are released via the cooling water, which is heated by up to 7˚C (given a volume of 70-80 t/s or 6.9 million t per day at an NPR with 1 GW output). Thus, NPPs contribute to global warming by raising the sea water temperature without the detour of CO_2 emissions (Koide 2011a, 118-21; Saitō 2011, 26-9).

Nuclear power generation needs fossil fuel fired power plants as backup and complement to keep the total output responsive to demand changes. After 3/11, CO_2 emissions increased despite a decline in electricity generation: load, output and weight of hard-coal and LNG-fired power plants had been raised to replace previous NPP capacity. Already 1990-2010, the CO_2 emissions from electric power generation and their share of Japan's total

73 According to the calculation model of the WISE-Uranium project (2009b), the production of 30 t UOX fuel causes an energy consumption of 292 GWh and 314,337 t CO_2 emissions. This translates into 53.8 g CO_2/kWh, converted to the annually generated electricity volume of a 1 GW reactor with 70% utilization minus the energy consumed for operation.

Chart 3.27a CO_2-emissions of electric power generation after credits and their weight on total CO_2-emissions of Japan (CY)

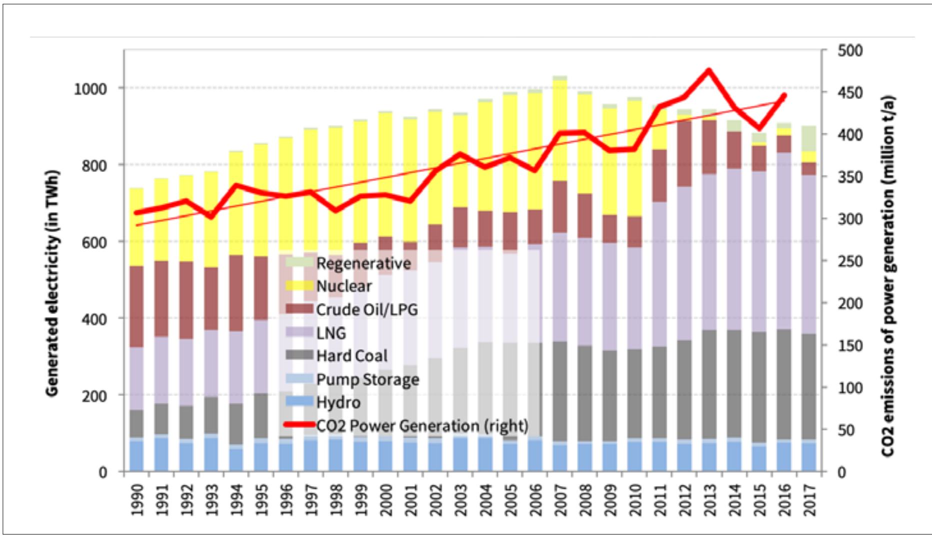


Source: Author, based on METI 2018b, 2018c; GIO 2018

emissions showed a trend that contradicted the common claim, that nuclear power is vital for the fight against global warming. Both parameters, CO_2 emissions from electric power generation and their share of Japan's total emissions, increased due to the increase in total volume and composition of electricity production, namely, the combination between nuclear power generation and coal-fired power generation (charts 3.14, 3.27a-b).

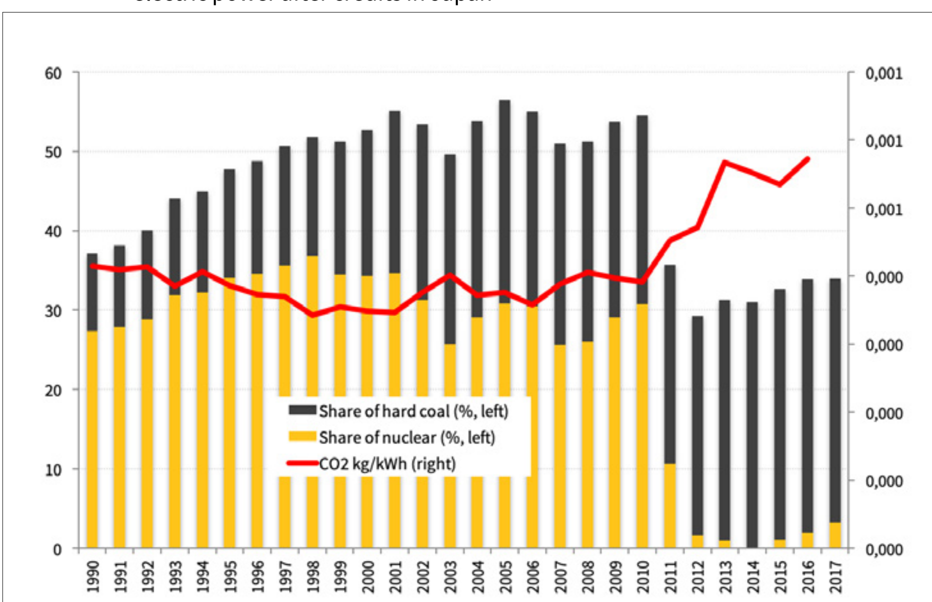
In other words, the CO_2 emissions per unit of total electricity generated had not fallen significantly. By the end of the '90s, the share of nuclear power in electricity generation had risen to more than 35%. Despite the simultaneous increase in the share of coal-fired power plants, CO_2 emissions per unit of electricity generated declined slightly in the beginning. However, entering a new phase of increased seismic activity and troubles, utilization rate and share of NPP/NPR in power generation fell. In response to that, the load of coal-fired power plants rose. The partial liberalization of the electricity market in the high voltage segment led to a further increase in the share of cheaper coal-fired power plants until 2003. Due to the high load of coal-fired power plants CO_2 emissions per unit of electricity generated went up again (chart 3.28). This was effected by the structural entwinement of nuclear power and coal power as the main form of centralised power gen-

Chart 3.27b Annual commercial electricity generation (exluding in-house) by energy source and its total annual CO_2 emissions after credits in Japan



Source: Author, based on METI 2018b, 2018; GIO 2018

Chart 3.28 Share of nuclear and hard coal power generation and CO_2 emission/generated electric power after credits in Japan



Source: Author, based on METI 2018b, 2018c; GIO 2018 eration: The commercial use of nuclear power inheres a tendency towards expanding electric power production (and consumption), whereas coal-fired electric power generation tends to be used as baseload complement to absorb demand increase, as long as coal price and CO_2 emission rights are cheap. Hirata estimated, that the volume of CO_2 emission by all planned new 40 coal-fired electric power stations in Japan (as of 2018) is equivalent to 10% of Japan's total CO_2 emissions in FY2014 (Hirata 2018, 42).

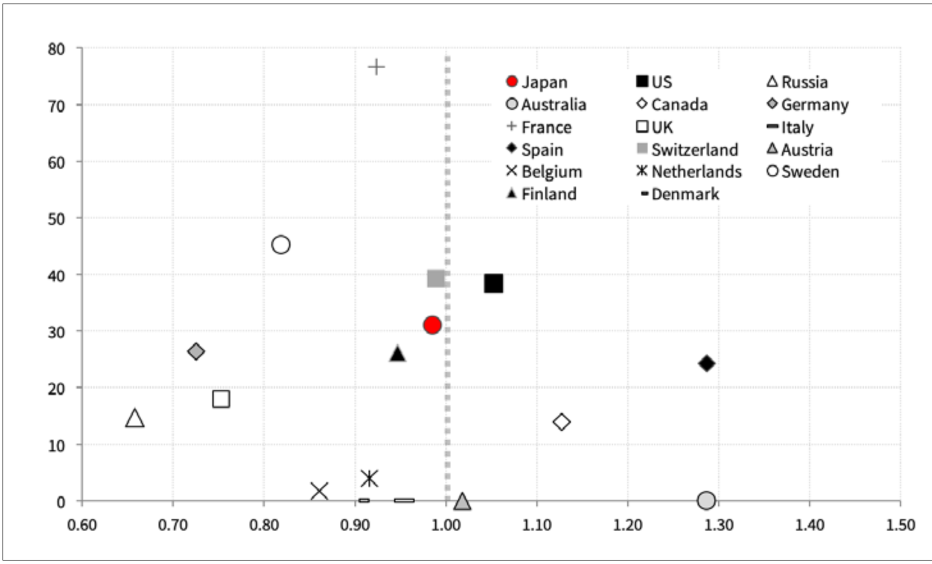
An international comparison of the weight of nuclear power in total electricity generation and the reduction in CO_2 emissions for the period from 1990 to 2009 demonstrates that a high proportion of nuclear power does not necessarily lead to significant CO_2 reductions (Yoshioka 2011b, 56-8). It is no coincidence that – in addition to countries with abundant fossil fuels such as Australia and Canada – Japan and the US performed poorly in reducing their CO_2 emissions despite a relatively high share of nuclear power generation before 3/11 (charts 3.29a-b). And it is no coincidence either that both Japan and the US have been promoting a Nuclear Renaissance. After all, they host the headquarters of five out of six NPP builders in the Western world (Tōshiba, Hitachi, MHI, GE and WH). These builders formed three global alliances in the mid-2000s: Tōshiba with WH, Hitachi with GE and MHI with AREVA. They have since been pushing their governments to provide them with business domestically and abroad.

It is precisely the combination of both nuclear and coal-fired power generation in the supply portfolio of Japan's former regional monopolies that is preventing a fundamental reduction of electricity consumption and the conversion of electricity supply to regenerative decentralised forms. In July 2012, Japan's government introduced a Feed-in Tariff (FIT) for renewable power generation (solar, wind, small hydro, biomass and geothermal power plants) at the relatively high level of 42 JPY/kWh (under 10 kW) and 40 JPY/kWh plus tax (over 10 kW) applying to 20 years for solar generated power and 10 years for all others.[74] The existing electric power producers, suppliers and retailers have also increased their renewable power generation capacity from 0.65 GW installed as of June 2012 (0.3% of their capacity) to 9.1 GW as of March 2017 (3.3%). Thus, the total capacity of renewable power generation has risen to 39.1 GW as of September 2017, which represents 13% of Japan's total power generating capacity (300.1 GW).[75] The respective volume of electricity production has changed from 13.3 TWh (1.4 %) in FY2011 to 58.6 TWh in FY2016 (6.4% of total production). 13.7

74 This FIT system was designed to reach a purchasing price of 24-26 JPY/kWh for under 10 kW over 10 years and 18 JPY (kWh) + VAT for 10 kW-2,000 kW over 20 years (METI 2018f).

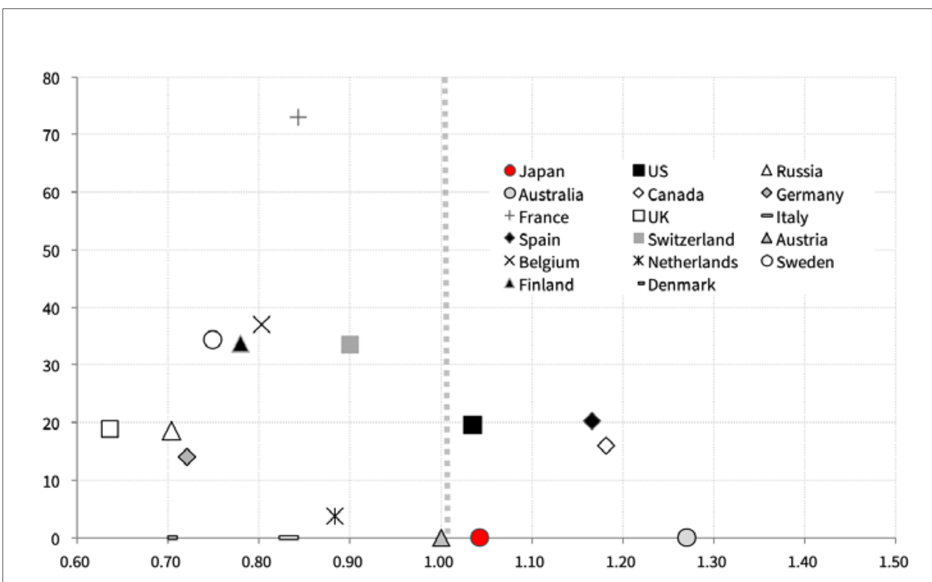
75 At the same time, a capacity of renewable power generation, amounting to 92.5 GW, was approved. This means that only 42.3% of the approved renewable capacity has been installed (METI 2018f).

Chart 3.29a Nuclear share in power generation (vertical, average 1990-2009 in %) and Green House Gas (GHG) emissions 2009/1990 (horizontal, 1 = 1990)



Source: Author, based on UNFCCC 2018; IAEA 2018b

Chart 3.29b Nuclear share in power generation (vertical, 2015 in %) and GHG emissions 2015/1990 (horizontal, 1 = 1990)



Source: Author, based on UNFCCC 2018; IAEA 2018b

TWh (1.5%) were generated by retail power suppliers and 44.9 TWh (4.9%) by others.[76] This means that renewables with a capacity share of 13% and a production share of only 6.5% have had an extreme low utilization rate, which is not only due to their dependence on volatile prime energy sources. They have also been systematically discriminated. Being denied grid access capacity, they are confronted with output restrictions – unlimited for solar power suppliers with more than 10 kW and limited for solar power suppliers with more than 50 kW. And they are charged high fees for upstream connection, transmission and unbalance absorption by the grid owners, i.e. the former regional monopolists (Wakeyama 2018, 31, 35).

Finally, it is noteworthy that 3/11 – the cooling system's malfunction, the meltdown of three NPRs and the ongoing aftermath – caused not only tremendous harm to humans,[77] but a substantial increase in energy and water consumption[78] and CO_2 emissions. These 'after-effects' include irreversible damages to human health and natural environment. In summary, it can be stated, that NPPs are an extremely dangerous,[79] inflexible and expensive way of producing electricity, and they do not provide a viable solution either for the global climate problem or for the increasing depletion and scarcity of natural resources.

3.4 Future Scenarios: Politics, Market and Technology

In Japan, too, the rise of nuclear power generation had rested on the interweaving of the state's industrial policy with the economic interests of an oligopolistic electricity industry. Initially, NPPs became part of companies' production portfolio because the state in general and the central government and METI in particular covered all the associated costs and risks as well as R&D. The industry was particularly interested in running its expensive equipment at a high utilization rate, while keeping variable costs as low as possible. In response to the fuel prices, it shifted its production

76 Calculation based on METI 2018b.

77 At least 80,000 persons and 28,600 families were forced legally to give up their homes; and another 440,000 persons left their homes to escape from radioactive pollution (Saitō 2015, 104, 111).

78 According to TEPCO and METI, 1 million m^3/t of tritium, strontium and cesium contaminated water is stored in tanks at the Fukushima-1 NPP site (increasing by 150 t per day), 50,000 m^3/t of highly contaminated water is still remaining in the underground of the NPRs, both as of July 2017 (TEPCO 2017).

79 The only rational justification for the leverage rate of tax-financed subsidies to construct power generation capacities would be that it represents a risk premium for NPP/NPR locations, being set at seven for NPPs, five for hydropower plants five and three for fossil fuel-fired power plants (Kumamoto 2011, 137).

portfolio from hydropower to coal in the ’50s and from coal to oil in the ’60s. It was only after the oil price shocks of 1973 and 1979 that nuclear power gained momentum. Nuclear power was expected to warrant independence from crude oil imports and, thus, to ensure electricity production at supposedly low cost. Its alleged role was tied to the ideology of growth and expansion. Since the late ’90s the expansion of nuclear power generation has become a central matter of survival for the former regional monopolists and their centralised electric power system, especially in view of the global shift towards renewable and decentralised power technologies, liberalization and new business models. In this process, the dependency of the electricity companies on the state has increased, as they are part of the ‘nuclear complex’ that consists of the central government bureaucracy (METI and MEXT), state regulation and control commissions (AEC, NRA), NPP/NPR operators and their association (FEPC), NPP/NPP builders (organised as JAIF), financial institutions (commercial banks, brokerages or investment banks, insurance companies) and general trading companies, political parties and members of parliament, municipalities, universities, mass media and international institutions (IAEA, UNSCEAR). This complex serves the interests of its members aiming at immunity against economic competition and democratic control[80] – which raises the issue of options. To understand the potential scope of decisions and actions, compact scenarios about how to handle the aftermath of 3/11 and the problematic structure of power generation in the future, can be conceived as follows:

Scenario A: “Fukushima 2.0: Japan is sinking”[81]

Responsibilities for 3/11 remain unquestioned and violations of existing laws unprosecuted. The costs are not borne by those who cause them. They are socialised but only insofar as they are officially recognised as costs. Beyond that, the victims are left alone. TEPCO will not go bankrupt and stay listed at the stock market, maintained by means of public funding and electricity price increases. Lenders and shareholders of TEPCO will not be charged for the liabilities of 3/11. Supported by Japan’s big corporations, the FEPC member companies and the state continue to interlock with each other, nuclearising the power industry and affecting Japanese society under the label of state security until the next nuclear disaster occurs.

80 Takagi 2000a, 33-5, 47-67, 98-121, 124-56; CCNE 2017, 281-3.

81 Hirose 2012a.

Scenario B: 'Political Turn: Local Initiative from the Bottom, Followed Nationally from the Top'

Common awareness of the total costs and risks of nuclear power generation is growing together with a critique of the plutocratic execution of political power by the nuclear complex. Readiness to bear the temporarily additional costs for an exit from nuclear power generation is increasing. The anti-nuclear movement assumes the form of an open network and joins the professionally organised movement for democratisation and environmentalism, allied with NPO/NGOs and businesses from new industries. Reform-minded regional leaders push for decentralisation, opposing the state bureaucracy as well as established political parties with regards to energy policy. This movement becomes so influential that political coalitions start to implement the phasing out of nuclear energy against the interests of the state bureaucracy and large parts of Japan's traditional big business.

Scenario C: 'Economic Evolution: Selection by Market Liberalization and Free Competition'

The costs of nuclear power generation are increasingly included in a still regulated electricity price ('Nuclear FIT'), and consumer prices, sensitive to electricity, are rising to such an extent that a fundamental liberalization of the electricity market with equal starting conditions for all participants can no longer be prevented. The ownership of the power grid is separated from the electricity companies and consequently the access is neutralised. As a result, the share of independent local power generators and non-nuclear alternative offers grows, benefitting from falling costs for renewable power generation, energy storage and network technologies. The subsidisation or socialisation of the costs of nuclear power generation is losing ground, and its scope is declining. NPP-centred electricity companies are ultimately too cost-intensive to be still competitive.

In reality, these three scenarios will most likely intertwine, absorbing, trading-off or boosting each other. The crux of the problem, however, is what Crouch (2011) described as the very nature of neoliberalism: to put state and market not in stark contrast, as it appears to be, but in close interdependence, which allows large corporations to exploit both of them at the expense of wide sections of the working population, consumers, democratic control, society and nature (Crouch 2011, ix). Neoclassical theory assumes the following conditions for markets to be efficient in allocating resources and evaluating outcomes of economic activities:

a. prices are comparable;
b. resources and products are tradeable;
c. market entry and exit are free from obstacles;

d. a large number of sellers and buyers are optimally informed and ensure a high transaction volume through their interactions;
e. economy and politics are separated from each other.

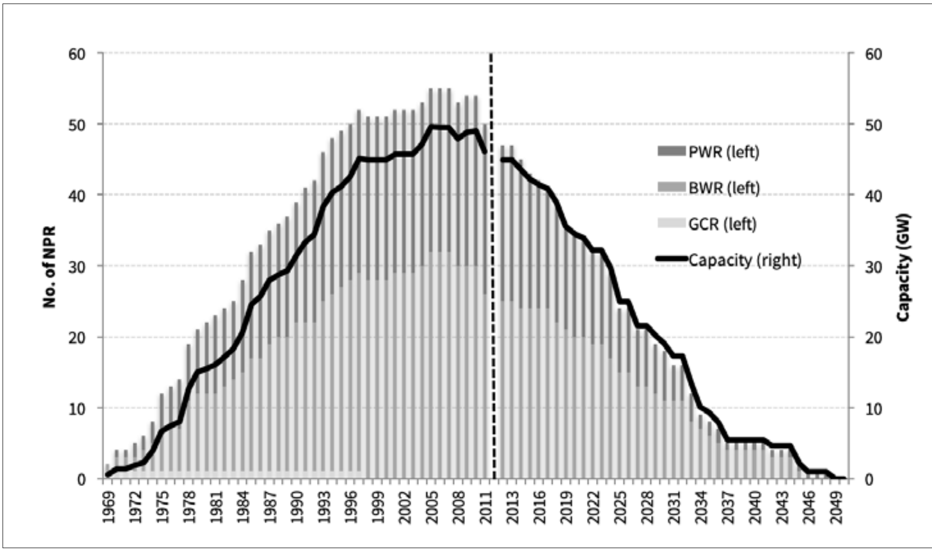
However, today, structural deviations from these conditions, i.e. market failures, are the rule: important costs of offers, their production and corporate failures are externalised or more precisely, socialised. Supply competition is restricted or prevented by barriers to market entry and exit. So are the choices for consumers. Critical product features and parameters as well as costs and prices are kept non-transparent. The interests of large corporations increasingly influence political and state action (Crouch 2011, 34-48).

Thus, the pure economic logic alone – fundamental market liberalization (following scenario C) – will not be sufficient to denuclearise Japan's electricity industry. Equal access for market participants and prevention of centralisation require political intervention into existing ownership rights as well as public rules for economic activities, which go far beyond the symbolical avoidance of 'over-exploiting' economic power in single cases. However, the current course of response to the problems in Japan shows that the nuclear complex is still able to protect the interest of its members, that is, to cope with the 3/11 disaster and the new stage of liberalization; it is socialising the costs caused by its own conduct (following scenario A). In September 2012, the then acting Japanese government decided to begin reducing the dependency on nuclear power generation by (a) decommissioning all NPRs that were older than 40 years, (b) restarting only those younger NPRs that passed the NRA security check and (c) not increasing the existent capacity, for example, by building new NPRs. Pushed by critical public opinion, the government went even a small step further and declared its aim to phase out nuclear power generation before 2040 (Enerugī kankyō kaigi 2012, 6) (charts 3.30a-c).

But the election of December 2012 was won by the conservative Liberal Democratic Party, led by right-winger Shinzō Abe – with 43.0% of votes (by 24.7% of all eligible voters) given to direct candidates and 27.6% of votes (by 16% of all eligible voters) given to the central candidate lists (MIC 2018f). Assuming the reins of government the LDP annulled all measures and laws that promoted the exit from nuclear power generation. Scenario A prevailed over scenario B. Reversely, the examples of Taiwan and South Korea, where centre-left governments declared their intention of exit, evince how much nuclear power generation depends on state protection and public funding, which makes it extremely vulnerable to political change. For such change a countervailing force is needed including grassroots, political, religious, civil and consumer rights, non-profit and professional movements in an alliance that restricts state and economic power and their entanglement (Crouch 2011, 162-80).

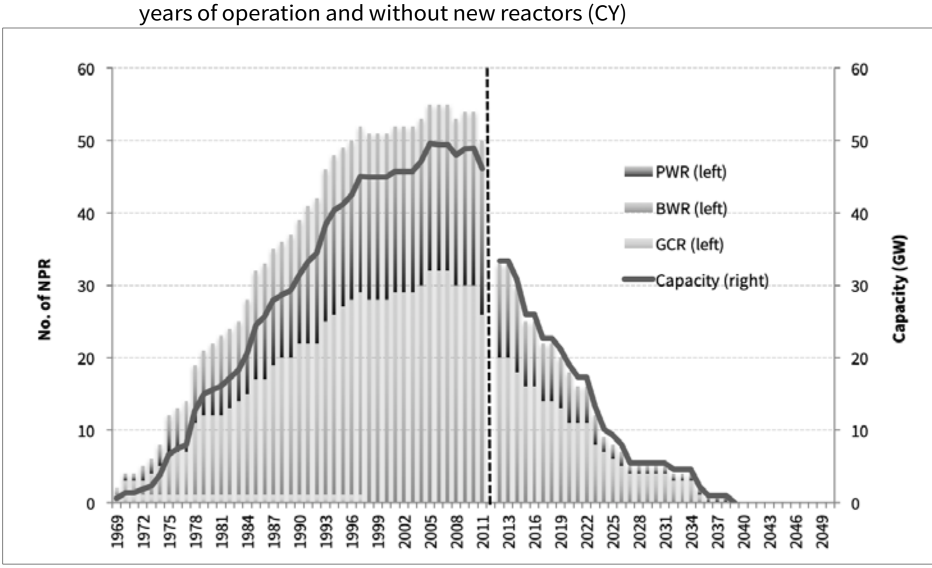
Among the respondents to opinion polls conducted by the newspaper *The Asahi Shimbun*, an obvious majority has been against nuclear power gen-

Chart 3.30a Number of commercial NPRs and capacity until 2011, decommissioning after 40 years of operation and without new reactors (CY)



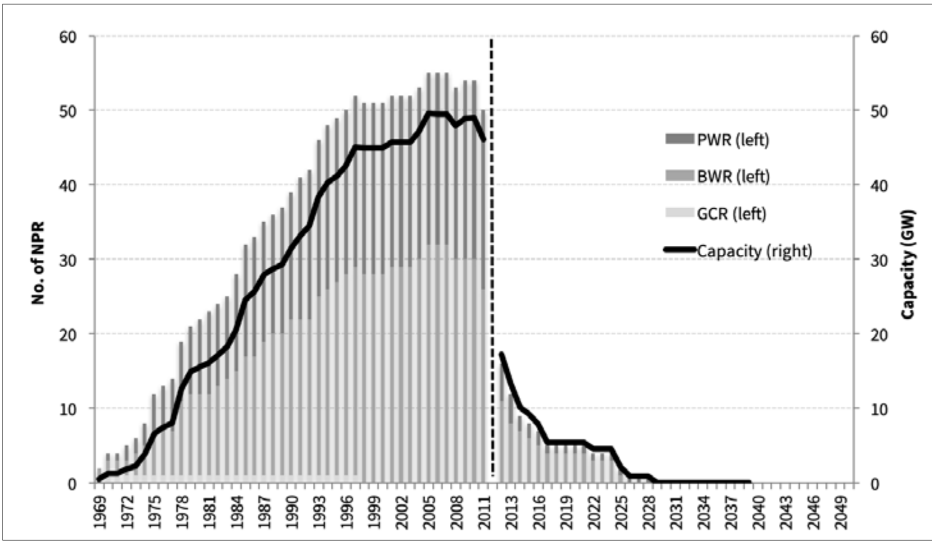
Source: Author, based on JNES 2013

Chart 3.30b Number of commercial NPRs and capacity until 2011, decommissioning after 30 years of operation and without new reactors (CY)



Source: Author, based on JNES 2013

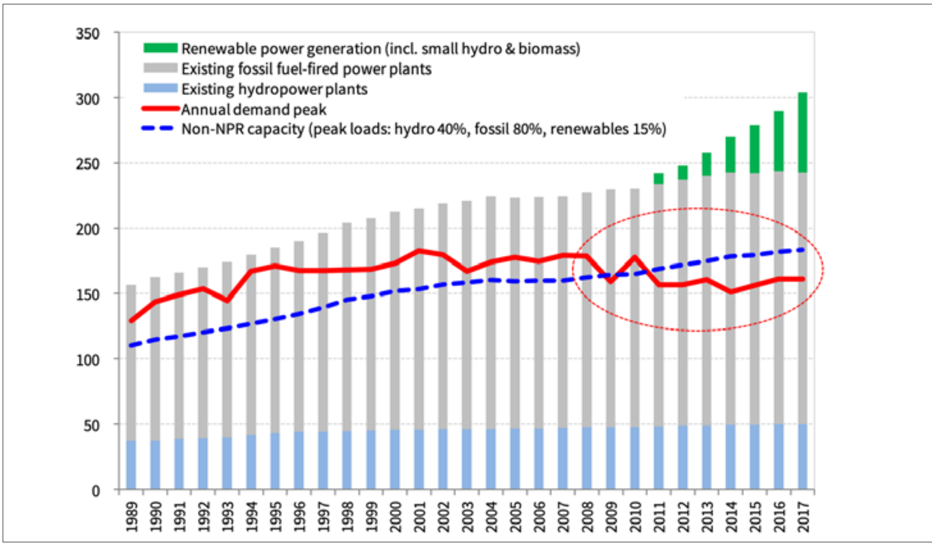
Chart 3.30c Number of commercial NPRs and capacity until 2011, decommissioning after 20 years of operation & without new reactors (CY)



Source: Author, based on JNES 2013

eration since May 2011, in favour of an exit from nuclear power in the near future since January 2014 and disapproving of NPP/NPR restarts since June 2011 (Tsuda, Kojima 2017, 12-3). However, acting prime minister Shinzō Abe and the ruling LDP have won a clear seat majority in two more parliament elections since 2012. In the election in December 2014, LDP secured 48.1% of votes given to direct candidates (by 24.5% of all eligible voters) and 33.1% of votes given to the central candidate lists (by 17.0% of all eligible voters). In November 2017, LDP obtained 47.8% of given votes to direct candidates (by 25.0% of all eligible voters) and 33.3% of votes given to the central candidate lists (by 17.4% of all eligible voters) (MIC 2018f). Not surprisingly, these election results have been interpreted also as approval of LDP's policy of promoting nuclear power. But, in actual fact, a negative perception of nuclear power generation prevails among Japan's population, particularly woman, which can be deduced from the fact that most opposition parties have made the future exit from nuclear power generation part of their political agenda. Furthermore, candidates for governors in prefectures with NPP locations, who claim the same or are cautious about restarts, have won prefectural elections with relatively large margins over nuclear power proponents, such as in Kagoshima (July 2016) and Niigata (October 2016) (CCNE 2017, 287). Former prime minister Junichirō Koizumi, who was a strong proponent of nuclear power during his time in office (2001-2006),

Chart 3.31 Installed non-NPR capacity (incl. self-producers, FIT) and demand peak in Japan (FY, GW)



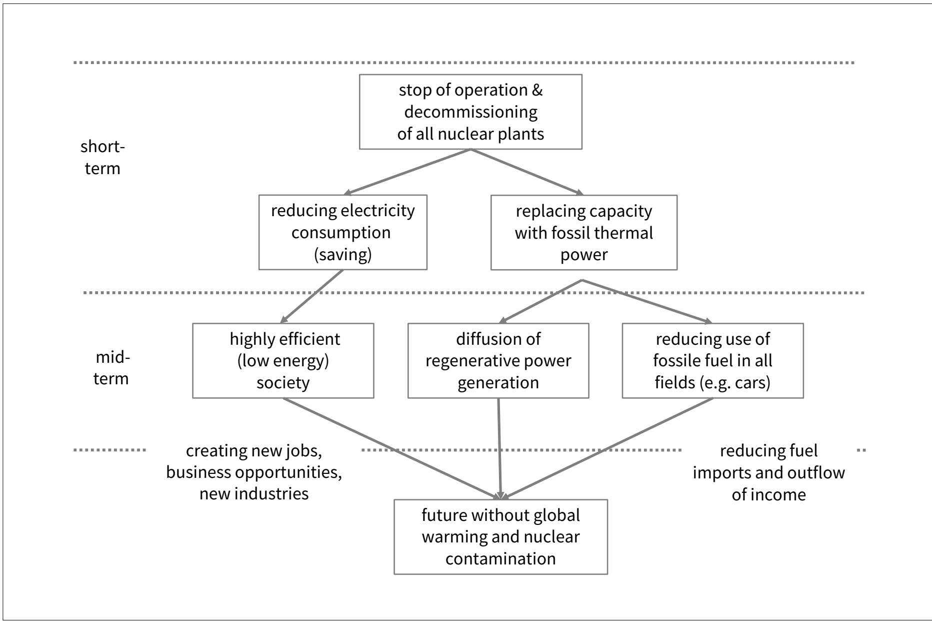
Source: Author, based on METI 2018b, 2018c

has turned into a critic of the government's energy policy since 3/11, urging for an early exit (Koizumi 2017). Even among acting LDP politicians, parliament members and cabinet ministers, there are outspoken critics of the current government policy in favour of the nuclear complex, such as Tarō Kōno.[82] The central question is how to integrate the demand for an early exit from nuclear power into a strategy for a fundamental reform of social and economic policy, creating an attractive platform to join forces against the nuclear complex and mobilising the silent, not voting majority.

Japan has shut down all NPPs without suffering from a severe and chronic shortage of electricity supply. Contrary to allegations and campaigns by electricity companies, government, business associations and right-wing mass media, demand reduction through energy savings had already been realised in the summer of 2011 and the following winter, when private households, industries and businesses decreased their electricity consumption by 15-20% (Nagatomi 2013). As proven back then, it is sufficient to run temporarily all installed fossil fuel-fired plants with a 80% peak load, hydropower plants with a 40% peak load and renewables power plants with

82 URL `https://www.taro.org/category/policy/energy` (2018-10-24)

Figure 3.8 Logic of exit from nuclear power in Japan



Source: Author, based on Kamioka, Oka 2012, 7

a 15% peak load[83] in order to cover the annual peak of electricity demand without any NPP/NPRs (chart 3.31).

As of March 2017, the installed capacity of renewable power generation has not only expanded to 46 GW, but additional 70 GW (both including small scale hydro and biomass) have been approved and are waiting to get installed, connected and operated or have applied for approval. Obviously, it is possible to decentralise production, distribution and consumption of electricity and even to reduce operating costs, after an investment peak for building a flexible network with new energy storage facilities in order to replace NPPs and hard coal fired power plants as baseload capacity, absorbing supply volatility. Producers and consumers can move to modes

83 During the demand peak periods in summer 2011 and the following winter, KEPCO, with 40.8% (9.76 GW) of its total generation capacity (23.93 GW) most heavily dependent on NPP/NPRs (as end of FY2010), expected for its supply area a temporary shortage of electricity supply. But the decrease of supply by NPR/NPP taken out of service (minus 6.0-8.4 GW) was compensated mainly by reducing demand (voluntary savings), increasing load of fossil fuel power plants and providing surplus capacity temporarily from the regional monopolists in the neighbouring areas and self-producers (KEPCO 2011).

of production, mobility, transport and consumption based on an efficient and regenerative use of energy resources, instead of relying on the expansion of electricity production. Decentralisation would ignite an industrial and societal change that leads out of the deflationary spiral of cost and price reduction, social degradation and destruction of nature (fig. 3.8).

In 2012, Takashi Hirose, veteran thinker of the anti-nuclear movement in Japan, made a proposal with regard to how political movement and economic policy could be linked, namely, by turning consumer power towards generating a practical alternative for NPP operators. He suggested withdrawing almost all savings from the large banks, the big lenders to KEPCO (which was the frontrunner in restarting NPRs after 3/11) and deposit the funds in savings accounts at banks that support the replacement of nuclear power by renewables such as the Jōnan Shinkin Bank (Jōnan Shinyō Kinkō). He called also for voluntarily accepting electricity price raises, if the surplus were used for paying the additional cost (mainly for fossil fuel) incurred from replacing nuclear power with other supply capacity (chart 3.32a), and buying out all NPP assets from the electricity companies (chart 3.32b), thereby taking NPPs out of service (Hirose 2012b).

Fearing financial losses, shareholders, lenders, managers, employees, unions and vendors of NPP operators have been pushing for a quick restart of NPRs. Their fears need to be released, by making their business sustainable in alternative ways. For that, all electricity consumers should agree to pay the extra cost for alternative power supply and additionally donate the funds needed to buy out the NPP assets at book value (charts 3.32c-d).

Hirose (2012b) estimated that the additional expenses to be paid by every household in Japan would be bearable, that is, at a level of 500 JPY/month or one cigarette package. Actually, by now, most of the additional fuel costs are already included in the post-3/11 raise of the regulated electricity price and thus charged to the private households anyway. However, assuming (a) a replacement supply composition of 75% LNG and 25% hard coal, (b) a 20% nuclear share in electricity production (which was the average 1970-2016) and (c) an equal participation of all electricity consumers (corporations and private households, ultra-high, high and low voltage, regulated and non-regulated) in the donation campaign for buying out all NPP assets at book value, the additional expense would amount to about 2.5 JPY/kWh[84] for a period of five years. For private households with an average electricity consumption of about 370 kWh/month, this would create bearable additional cost of less than 1,000 JPY/month or two packages of cigarettes. Yet, Hirose's proposal

84 (A) 1.3 JPY/kWh for additional non-nuclear fuel cost + (B) 1.2 JPY/kWh for NPP asset buyout = 2.5 JPY/kWh; A = [(7.1 JPY/kWh − 1.2 JPY/kWh) × 0.75 = 4.425 JPY/kWh] + (5.6 JPY/kWh − 1.2 JPY/kWh) × 0.25 = 1.1 JPY/kWh)] × 0.2 = 1.325 JPY/kWh (chart 3.32a); (B) = Sold electricity weighted average raise of electricity price over five years (chart 3.32d).

for immediate action has been ignored by the mainstream mass media and political organisations.

Another way of replacing nuclear power is to systematically save energy and install renewable power capacity (fig. 3.8). As Hiroshi Takahashi (2018) has shown (tab. 3.3), this would be not just a functional, but a systemic shift from a monopolistic industry, a centralised, hierarchical and scale-driven business model and an economy dominated by large corporations and the nation state to its opposite, that is, an open-structured industry with various players and organisations, decentralised, diverse business models and an economy of regions and communities based on network collaboration and market competition.

Table 3.3 Chart of energy shift

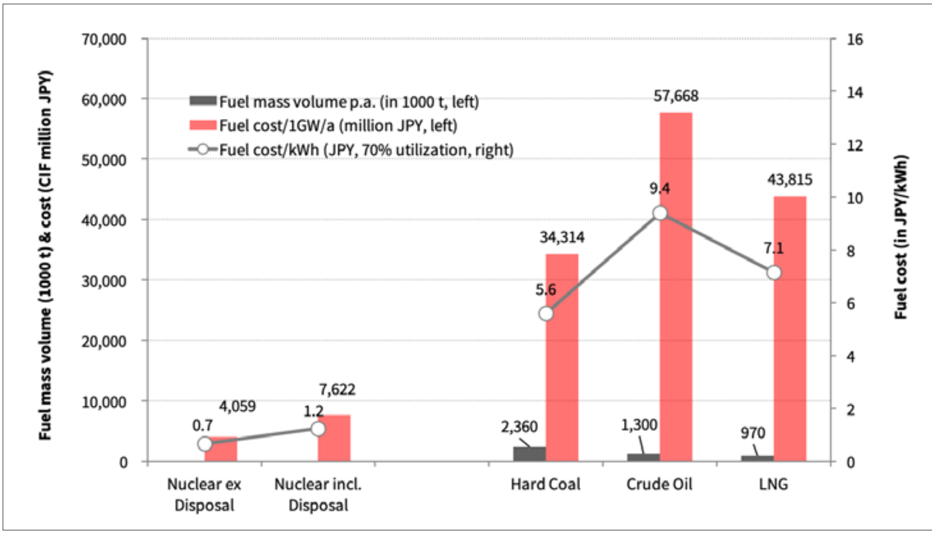
	Centralised energy system	Decentralised energy system
Energy power source	Centralised: nuclear, hard coal thermal	Decentralised: renewables, co-generation, energy saving
Main business actor	Large corporations as monopolies	Various regional and local firms and NPOs
Main policy actor	Central state	Municipalities and central state
Economic principle	Monopoly/plan: economy of scale	Competition and market, autonomy and collaboration
Network logic	Central administration, hierarchy	Decentralised, dispersed, open, mesh: fitting
Role of consumers	Passively, limited	Active and diverse: prosumer
Environmental fit	Low: restricting waste and pollution	High: low carbon, safety, harmony with nature
Regional link and fit	Low	High
Experience, history	Long, certainty	Short, uncertainty

Source: Hiroshi Takahashi 2018, 57, based on Ōshima et al. 2016

According to the Sustainable Zone Report, the number of municipalities in Japan that can meet their demand for electricity solely by means of renewable sources in their region rose from 84 in 2012 to 136 in 2017. In the same period, the number of municipalities that can cover both heating and electricity demand by own renewable supply increased from 50 to 82. The rate of regional renewable energy supply, indicated as share of the total regional energy demand, went up from 3.8% to 10.5% (Kurasaka, ISEP 2018, 8) (chart 3.33).

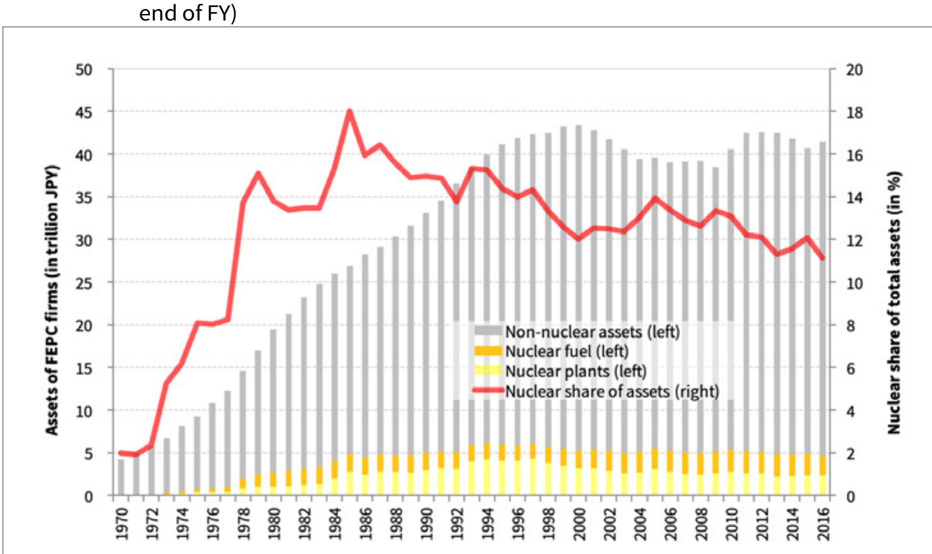
At present, the ancient regime resists this fundamental change. Electricity consumers, and particularly private households, have to pay increasing electricity prices without being liberated from the costs and risks of nuclear power generation. Neoliberal redistribution of wealth, favouring the members of the nuclear complex, is still dominant. But earthquakes do not

Chart 3.32a Fuel mass volume and fuel cost for 1 GW/a at prices as of March 2017



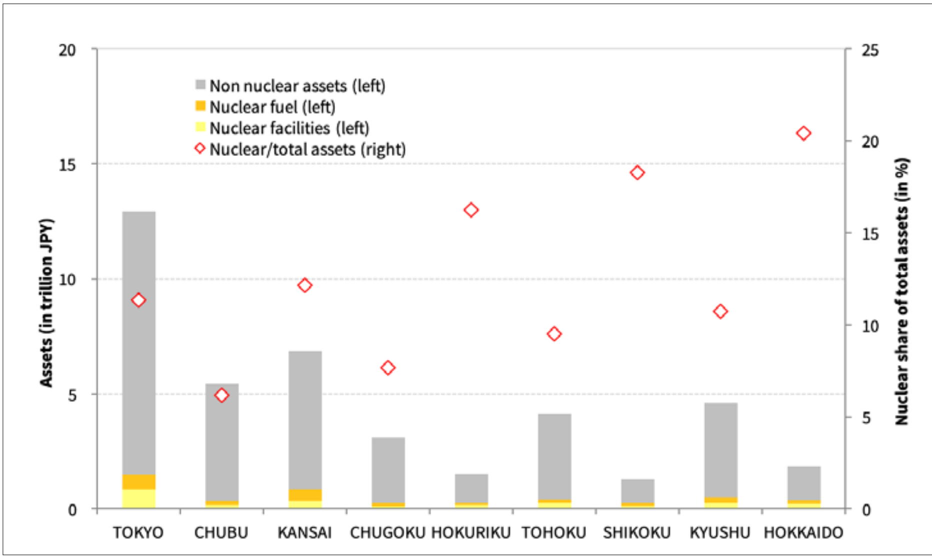
Source: Author based on RIST 2005; WISE Uranium 2009a, 2009b, 2009c; Japan Customs 2018

Chart 3.32b Book value of nuclear plants and fuels as share of total assets at FEPC firms (excluding Okinawa's electric power and Japan's atomic power company, end of FY)



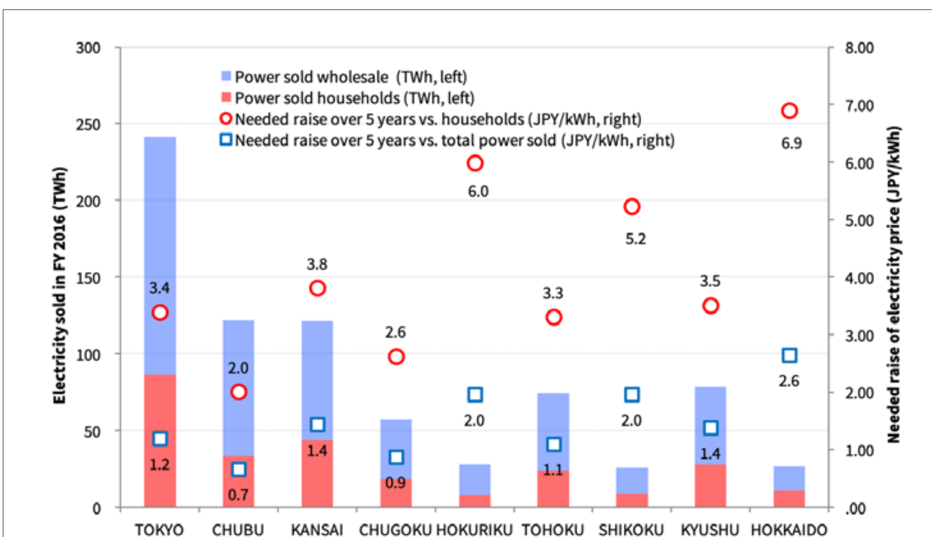
Source: Author based on IR-Reports, FEPC (2018)

Chart 3.32c Nuclear plants and fuels as share of total assets by FEPC firms (excluding Okinawa's electric power and Japan's atomic power company, as of end of FY2016)



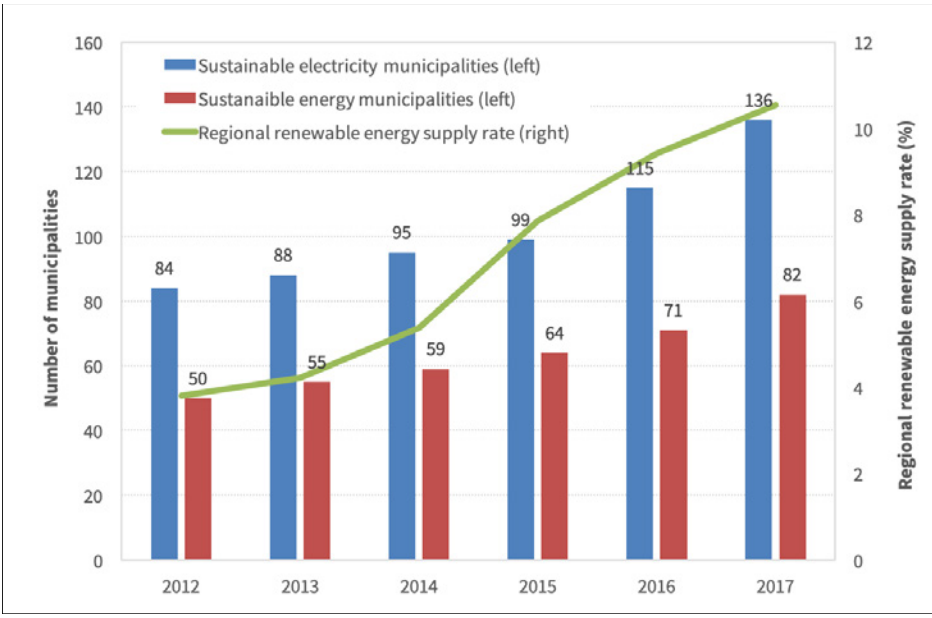
Source: Author, based on IR-Reports for FY2016

Chart 3.32d Sold electricity (households/wholesale) and price raise needed to buy out and write off all nuclear assets over 5 years by FEPC firms



Source: Author, based on METI 2018b; IR-Reports for FY2016

Chart 3.33 Number of municipalities with sustainable electricity and energy in Japan



Source: Kurasaka, ISEP 2018, 8

wait. Thus, the high probability persists that ‘Fukushima 2.0’ (scenario A) occurs. The citizens’ right to a life without deprivation calls for structural changes in industries, business models and the economy at large. This involves a fundamental cultural shift.