Title page

A 100 Year Review of Electricity Policy in Ireland (1916-2015)

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Abstract

Over the past century, Ireland's electricity sector has undergone a significant transformation. This paper documents the nation's struggle to build an electricity system, to improve security of electricity supply through portfolio diversification and to promote indigenous energy sources. This was a challenge for an (electrically) isolated island with little natural resources. The paper also identifies the ineffective policy decisions that left Ireland exposed to the 1970s energy crises. The crises did, however, provide a clear impetus for focusing Irish energy policy going forward. The successful deployment and integration of large-scale wind power was due to strong national and supranational policy decisions. In 2015, Ireland had the third highest wind energy share of national electricity demand (22.8%) of all IEA Wind Member Countries. The paper also traces Ireland's transition through market reform, regional fragmentation, and looks onwards to the EU internal market for electricity. In essence, this paper provides a holistic view of the implications of various policy decisions on the electricity sector along with the stresses of external factors on the electricity market and should be useful for policy makers elsewhere faced with similar decisions.

Keywords:

Electricity sector policy, Single electricity market, Evolving electricity market, EU Target Model, Historical review, Ireland.

1. Introduction

Over the past 100 years, Ireland’s electricity sector has experienced significant change. Through the foundation of the State, World Wars, and Energy Crises, the sector has continually expanded, bringing affordable electricity to the most rural parts of the country. The establishment of a national organisation to bring together small undertakings under one roof to build, maintain and continually develop the sector is common across developed countries. The struggles of many to improve security of supply during and after the 1970s oil crises is also well documented. Ireland’s evolution over the last century differs however to that experienced in many other countries due to its geographically isolated position on the periphery of Europe, its lack of fossil fuel resources and its own geopolitical unrest.

Historical reviews of this type can deliver key learnings surrounding the establishment and continuous development of a sector. In other words; distilling the knowledge gained over an extended period to help decision makers in countries under development. Reviews carried out by FitzGerald et al. [1] and FitzGerald [2] have previously focused on Irish energy policy in the broader context, opting for an entire energy sector view. Both papers view modern-policy decisions (generally starting around the 1970s oil crises) and provide an insightful assessment of the entire energy sector, mainly focusing on aspects such as Security of Supply, Energy Needs of a Growing Economy, Competitiveness, Drivers of Change and Renewable and Environmental Policy. While O'Riordan [3] published a review outlining the development of Ireland’s power system between 1927 and 1997, it did not elaborate on the policy measures in place during the time. International review papers based on the electricity sector also tend to be theme related, with numerous papers concentrating on market liberalisation [4-36], climate mitigation [37-58] and market dynamics [59-87], while others can be infrastructure and technology specific [52, 53, 57, 61, 88, 89]. This paper, on the other hand, begins before the foundation of the state and examines the different stages of development in the electricity sector over 100 years, with a clear focus on the role of policy. From the early infrastructure-related decisions surrounding generation capacity and network development, to the lack of policy decisions pre-energy crises that left the nation exposed and resulted in a renewed focus on energy policy domestically that led to improved security of electricity supply through diversification of the generation portfolio with coal, peat, natural gas and later, wind power being promoted. This paper also examines the role of electricity market liberalisation and regulation in the founding of the all-island single electricity market, in what was a significant step closer to the long-term plan; establishing the European internal market for electricity. The role of climate mitigation policies is also explored, which prompted the rapid growth of wind power in Ireland. And finally, some residual effects from the numerous energy policies on market dynamics are highlighted, raising concerns over modern-day market structures and their ability to host the anticipated future generation portfolio.

The paper is structured as follows. Section 2 summarises the establishment and development of the electricity sector along with the diversification of the generation portfolio over the past century. Section 3 focuses on market liberalisation and regulation, outlining the phases that the Irish electricity market went through, from monopolistic control to complying with the EU Target Model. Section 4 describes the role of climate mitigation policies played in electricity generation, while Section 5 concludes the paper, highlighting several policy implications.

2. Development of the electricity sector

The electricity industry had been in operation for more than 40 years before Ireland's first nationwide electricity market was established in 1927. The industry started small and was primarily based around the capital, Dublin, where local authorities and private companies generated and supplied electricity. Ireland was a political constituent of the United Kingdom (UK) until 1922, and as a result, the electricity sector developments in Ireland reflected that of the UK, albeit at a slower pace. The development and progress of the sector was both slow and uncoordinated due to the high number of small undertakings without any common long-term policy-driven plans [90].

In the early 1900s locally generated electricity (from either small-scale hydro or coal) spread across Ireland to the main municipalities. During the First World War, when coal rations were implemented, a paradigm shift in electricity generation occurred when the British Board of Trade investigated all indigenous sources of energy in the UK [91]. During this period plans to generate energy from large-scale hydroelectric plants located on Ireland's waterways were presented. One such proposal played a defining role in the development of Ireland's electricity sector; harnessing the River Shannon.[1]

2.1. The Shannon hydroelectric scheme, 1925

Harnessing the energy of Ireland's longest river, the Shannon, was one of the first major developments of the newly formed Irish Free State.[2] Spear-headed by the Irish engineer Dr. Thomas McLaughlin while employed by German company Siemens-Schuckert, the Shannon

[1] Sir Robert Kane had previously proposed to harness the hydropower from the Shannon in 1844. The potato famine halted any further developments on the project [92].

[2] The Republic of Ireland (referred to hereafter as Ireland) was initially known as the Irish Free State from its formation in December 1922 until 1937 when the constitution was changed [93].

hydroelectric scheme utilised a 30-metre head height on the river to deliver an electrical output of 85MW. McLaughlin's plans also included a supply network to distribute the electricity nationwide. Once commissioned the Shannon hydroelectric plant (referred to as Ardnacrusha due to its geographical proximity) was adequately sized to meet the entire national electricity demand in its early years of operation and to make Ireland's electricity sector 100% renewable.

After visiting the United States where, at the time, the electricity sector was more advanced, Ireland's newly formed first government decided that a public body should be formed to generate, manage and distribute the electricity generated under the Shannon scheme nationwide. Once passed into statutory law the Shannon Electricity Act, 1925 changed the outlook of the sector immediately as electricity was soon to be transmitted around the country. [90]

2.2. Establishing the Electricity Supply Board, 1927

The state-owned Electricity Supply Board (ESB) was established under the Electricity (Supply) Regulation Act, 1927 and placed in charge of operating, managing and maintaining the Shannon scheme, and distributing the electricity countrywide. In a move, which would have a profound effect on the future of the sector, the ESB turned down the option of selling electricity in bulk to other distributors, as allowed under the aforementioned Act and instead opted to deliver electricity directly to consumers on a non-profit-making basis. While the decision was strongly opposed by local authorities, it was made on the basis that local politics and municipal boundaries should not hamper the development of a national electricity network [90]. The decision removed the issues that caused slow developments in the past and instead presented a unified approach; aiming to create a nationwide electricity network.

The newly formed ESB, with the backing of the government, decided to acquire all existing electricity undertakings operated by local authorities, private companies, and small entrepreneurs.[3] As many of these undertakings employed different standards and voltages, this decision effectively harmonised the electricity supply nationwide. The result was a state-owned vertically integrated company that enviably gained the complete market share.[4] Once the last of the undertakings was acquired Ireland's electricity market became internalised within the confines of the ESB–something that would not change until 2000.

2.3. Sector development and rural electrification, 1930-1960

By the time Ardnacrusha was commissioned in 1929, the ESB had a transmission and distribution network (110/38kV) ready to transfer electricity nationwide, see Figure 1 for an illustration of the electricity network in 1930. This was a major development for Ireland and the first step in rural electrification. In 1930, Ardnacrusha and the coal-fired plant at Pigeon House, Dublin were synchronised for the first time, in what was a significant step to ensuring a stable electricity supply. Over the next decade generation capacity increased and electricity generation became more fuel diversified and geographically dispersed. New hydroelectric plants were commissioned and peat was considered as an alternative fuel source for electricity generation, in parallel with the pursuance of rural electrification policies. Priorities changed, however when the Second World War commenced. With coal rationed, peat was promoted as a viable alternative;[5] one that included the benefits of being indigenous, widely

[3] Prior to the Electricity (Supply) Regulation Act in 1927, there were 160 undertakings generating and supplying electricity in Ireland [94].

[4] It must be noted that evidence shows ESB providing electricity at a fraction of the price other companies charged at the time. See the ESB online archive for details [95].

[5] The First Development Plan was passed in 1946, calling for two peat-fired ESB power stations to be commissioned and 24 bogs developed. In 1950 the Second Development Plan forced ESB to commission four more plants on the western seaboard solely for socio-economic reasons [96].

available and, from a socio-economic point of view, advantageous to rural Ireland [57]. Plans for rural electrification suffered a setback during this period of unrest and it was not until the Rural Electrification Scheme (1946) and the Electricity Supply Amendment Act (1955) were passed that the electricity network started to reach the most rural and isolated communities in the country.

[Insert Figure 1]

2.4. The 1970s oil crises

After the rural electrification policies were implemented post-Second World War, the national electricity demand steadily grew and the ESB increased the generation capacity of the portfolio with new hydro, peat and oil plants commissioned. By 1970, 46% of Ireland's installed generation capacity was indigenous (peat and hydro) and 54% oil-based [3]. With even more oil-fired units in the planning phase, and yet devoid of any indigenous oil resources, this level of dependency left Ireland in an exposed position for the 1970s oil crises.

Both oil crises that occurred in the 1970s resulted from geopolitical instability. In each case, the sharp reduction in oil availability manifested themselves in the price of oil. The first in 1973/74 was triggered by American involvement in the Yom Kippur War, also known as the Arab-Israeli War. This caused the Organisation of Arab Petroleum Exporting Countries to declare an oil embargo which, over the following months, increased the price of oil globally from $3 per barrel to $12 [97]. The embargo was lifted in March 1974; ending the period known as the First Oil Shock. The second was a by-product of the Iranian revolution in 1979 and the Iran-Iraq War the following year. Iranian oil production was severely reduced over this period, causing panic and economic recessions around the world. Taking cognisance of the fact that global oil supply only decreased by 4% during this period, the price doubled to $39.50 per barrel [98]. After these events, it was widely considered that the era of cheap oil was over.

In the decade spanning both oil crises, Ireland's reliance on oil for electricity generation continued to increase. Oil represented 50% and 64% of primary energy used for electricity generation in 1970 and 1980 respectively [3]. Even with approximately 45% generation capacity fuelled by indigenous sources, the price spikes from oil had a telling impact on electricity prices in Ireland over the period, as seen in Figure 2.

[Insert Figure 2]

2.5. Diversifying the generation portfolio

In the 1950s the ESB had alerted the government to the exposure risk associated with over-dependence on a limited number of sources for electricity generation [94]. At first, the warnings related to hydro and peat but later, in the 1960s when the ESB had again raised concerns, the conversation had changed to oil. Unfortunately, the ESB were correct to voice concern in both instances according to Manning and McDowell [94]. In 1958/59 and again in 1963/64, Ireland experienced particularly wet weather conditions in one year and dry conditions in the following which affected peat harvesting and water levels in the hydro plants respectively, reducing the ability for peat-fired and hydro-based electricity generation. While in the late 1960s/70s, oil was affected by multiple events such as the Six Days War

(1967), the cutting of the Trans-Arab pipeline (1970) and both previously mentioned oil crises.

It was not until a series of events in the 1970s that energy policy in Ireland became focused and began to shape the electricity sector for years to come. First, the oil crises proved to the government that over-dependence on a single fuel source, especially a non-indigenous fuel susceptible to geopolitical instability, heightened risk exposure, Second, natural gas of commercial quantity was found off the south coast in 1973 which would lower Ireland's import dependency and third, nuclear power became an option for providing base load power [1].

During his description of Modern Portfolio Theory, Markowitz [100] explains how effective diversification can reduce or even avoid risk exposure completely. Applying this theory to a generation portfolio, as FitzGerald et al. [1] point out, means installing a number of fuel types with uncorrelated fuel prices to protect against any future price uncertainty–effectively acting as a hedging mechanism.[6] Over this period, and possibly unbeknown to itself, the Irish government started to implement Markowitz's theory by looking further afield at alternative energy sources to diversify the nation's generation portfolio.

2.5.1. Assessing the alternatives

Alternatives to oil-based electricity generation were examined to address concerns surrounding the nation's over-dependency on the commodity. It was found that hydropower was limited for further expansion,[7] peat offered little scope for development, coal was expensive compared to oil due to its labour-intensive nature, and other technologies such as

[6] History shows a high correlation between oil and gas prices [1].

[7] The only hydro plant of any significant size commissioned to this day was a 292MW pumped hydro energy storage plant in 1975. For more details, see: [3]

solar, wind power, tidal, and wave energy were not far enough developed to be considered a viable alternative. It appeared that nuclear power was the only serious alternative to oil for providing base load power in Ireland [94].

Over this period, gas-fired plants became more widely used in Ireland. Stemming from the newly developed indigenous gas resource along with advancements in gas combustion technology many oil-fired units were retrofitted to gas.[8] However, in the aftermath of the first oil crisis, actions were taken to ensure sufficient capacity margin was maintained for security of supply reasons. First, to meet short-term needs the ESB commissioned in excess of 500MW oil-fired capacity that was already in planning; further increasing the nation's reliance on the commodity [3]. Second, and much to the dislike of ESB, new peat-fired stations were commissioned through the Third Development Plan for security of supply reasons.[9]

2.5.2. *Nuclear power*

In the late 1960s, the ESB began gathering specifications for a nuclear plant with the support of the government who, at the time, indicated their openness to nuclear energy [94]. While the Nuclear Energy Act was enacted in 1971, establishing a Nuclear Energy Board and permitting the use of nuclear energy in Ireland, one of the main concerns was the minimum generating capacity of the plant. At 500MW the capacity was seen as too large for the Irish system at the time [94]. In short, the government did not want to commit to a major capital-intensive project that could be oversized and therefore, under-utilised and seen as a waste of taxpayer's money. Increasing demand through interconnection with Northern Ireland (NI)

[8] New combined cycle gas turbines achieved greater efficiencies than the widely used open cycle gas turbines operating at ~30%.

[9] In the early 1970s ESB stated that they did not regard peat-fired generation as a long-term solution and instead thought it prudent to plan for its phase out [94].

was a key component of this plan. However, this would prove difficult as the two existing transmission lines were regularly targeted for attack due to political instability in the region and as a result out of commission [3, 94].

By 1974, the ESB had drawn up plans and submitted technical and economic studies to establish a nuclear plant at five possible sites. The government appeared to agree with the ESB on the most suitable location of the project (Carnsore Point) and were looking to move forward with the project. Environmental concerns relating to nuclear energy were increasing across Europe, and in Ireland, as a growing opposition emerged targeting demonstrations at the various proposed sites around the country–prompting a negative public perspective towards the project. Acknowledging the growing discomfort around nuclear, the ESB drew up plans for alternatives. Coal was now the leading choice. The outlook for coal had changed since the previous studies were carried out, mainly due to the opening of an international market which broadened the supplier base, increasing competition. In addition to alleviating the concerns regarding nuclear, coal plants could also be built more quickly and in smaller unit sizes [94].

In 1978 a 'Green Paper' on energy policy was published.[10] This consultation document put the question of Ireland's future direction on energy policy to the public. However, before discussions could take place the second oil crisis triggered a global recession. With electricity demand expected to decrease due to the economic downturn and with the nuclear disaster in Three Mile Island in 1978, all nuclear plans were put on hold indefinitely. This informed the decision to build a large coal-fired base load plant at Moneypoint; originally one of the proposed sites for a nuclear plant. Two 300MW generating units were initially approved for the site but this increased to three at a later date, with the potential for a fourth [102]. The

[10] Energy-Ireland: discussion document on some current energy problems and options [101].

emphasis on energy supply security was evident in the provision of plans for expansion to a fourth unit, along with the fuel storage capacity of up to 2 million tonnes of coal (approx. one year's supply). Figure 3 shows the evolving generation portfolio in Ireland over almost a century.

2.5.3. *Moneypoint coal plant, excess generation capacity, and high electricity prices*

Moneypoint, Ireland's first large scale coal-fired power plant, was commissioned between 1985-1987. The plant added substantial capacity to the generation portfolio with a maximum output of 915MW (3 x 305MW units) at an investment cost of IEP £700 million[11] (€890 million) [95]. The capacity margin (the difference between installed capacity and peak demand) increased from the mid-1970s due to the commissioning of Moneypoint, as seen from Figure 3. For example, peak demand in 1977 was 71% of installed capacity compared to 56% in 1987. The excess generation capacity was considered a consequence of economic instability in the 1970s, a time when governments could not agree on macroeconomic forecasts, making long-term planning difficult. As a result, the ESB modelled future generation capacity needs using their own assumptions regarding; economic growth, fuel prices, and inflation [3, 94].

The forecasting errors and the timing of the extra capacity commissioned at Moneypoint was unfortunate as the economy performed poorly as alluded to by FitzGerald et al. [1]. FitzGerald et al. [1] also associate the high electricity prices experienced in the 1980s to this spare capacity which may not be completely accurate as the ESB, still to this day, cannot begin recovering capital costs from a project until after commissioning. Instead, from the evidence provided on the evolution of oil prices (Figure 2) coupled with the nation's over-

[11] Irish pound was the currency in Ireland until 2002.

dependence on the commodity over the same period (Figure 3) suggests fuel costs were a contributing factor in the continuous price rise and not solely costs associated to spare capacity.[12]

Over the next decade after Moneypoint was commissioned, electricity prices steadily decreased as a result of numerous factors working simultaneously, including excess generation capacity; no significant investment in new plant or infrastructure was required as assets were "sweated" according to Deane et al. [66], portfolio diversification; more gas and coal generation and a global reduction in oil and gas prices.[13]

The electricity systems of NI and Ireland synchronised for the first time in two decades in the mid-1990s as the transmission lines re-energised. Expanding the system proved a major success for Ireland in terms of security of supply. Not alone could electricity be imported from NI but it could also be generated in Great Britain (GB) and transmitted across the interconnector at Moyle.[14] It was not until 2012 that Ireland's electricity system became directly connected to GB when a 500MW interconnector was commissioned.[15]

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[12] Interest earned during construction contributed to repaying the capital required for the construction of Moneypoint power station.

[13] In the wake of the oil crises Ireland, along with many other countries, reduced their reliance on oil. This resulted in over-supply worldwide and the price of oil reducing for the first time since the second oil crisis. The overall decline in oil price continued over the following 20 years (even with the third oil crisis occurring in 1990) in what is referred to as the '1980s Oil Glut'. Gas prices also decreased during this period, dropping ~40% between 1985 and 1995 [99].

[14] The Moyle interconnector was commissioned in 2001. Owned and operated by Mutual Energy the interconnector connects NI with Scotland using two 250kV DC lines which can transfer a maximum capacity of 250MW each. For more information, see: http://www.mutual-energy.com/

[15] The East-West interconnector was commissioned in 2012. This project was developed and is owned by the transmission system operator; EirGrid. For more information, see: http://www.eirgridgroup.com/

2.5.4. The development of wind power in Ireland

The sector continued to develop and further diversify throughout the 1990s and into the 21st century. The history of modern-day wind power in Ireland is an example of this development when it began with the first major demonstration project at Bellacorick, County Mayo. The project, funded through European Commission under the VALOREN programme (Council Regulation (EEC) No. 3301/86), contained 21 Nordtank turbines with a combined capacity of 6.45MW [39]. After performing "*very well with an average load factor of 30%"* according to Staudt [55], the Irish government began supporting alternative energy sources in 1994 through a range of schemes and policy measures that aimed to encouraged investor buy-in and lower the institutional barriers facing the technology. This aspect of Irish wind power is addressed in Section 4 which discusses climate mitigation policies.

Through focused energy policy over the last three decades, the Irish wind power industry has grown significantly. For instance; at the end of 2015, the installed wind power capacity in Ireland was 2455MW according to the International Energy Agency [103], producing the third highest contribution to national electricity demand (22.8%) of all IEA Wind Member Countries. However, fulfilling ambitious policy measures can often depend on physics and the ability of the electricity system to absorb this variable energy. Any power system operating with high levels of variable energy yet limited interconnection or storage capacity must adapt quickly in order to maintain system stability. Ireland's electricity sector has done so in reaching instantaneous penetration levels upward of 55% (one of the highest levels for a synchronous island system globally), and continues to adapt with a new market structure that promotes flexibility through a new energy market design, improved system services and redesigned capacity mechanism, all to be implemented in 2018.[16] Notwithstanding the fact

[16] 23rd May 2018 is the date set out for Ireland to become compatible with the EU Target Model.

this transformation in Ireland's electricity sector is needed to comply with the EU energy packages (see Section 3 for further details), it is also necessary for the marketplace to adapt to the changing generation portfolio which requires flexibility and reliability to complement variable energy sources, maintaining a stable power system. The story of Ireland's market evolution from monopolist control to participating in the European internal market for electricity is outlined in Section 3.

[Insert Figure 3]

3. Market liberalisation and regulation

Liberalising the energy markets of Europe has long since been a goal for the European Union (EU) and the European Economic Community that existed beforehand [17]. Since joining in 1973, Ireland has been a member of the various regional organisations that aim to increase economic integration between Member States [105]. The long-term plan was to create a single internal market for free movement of goods, capital, services and people across the Member States [68]. As such, the establishment of competition laws to promote liberalisation within the internal market was a key aspect of EU policy–a paradigm shift away from the monopolistic market framework to a competitive alternative. For the electricity sector, this came in the form of EU Directive 96/92/EC,[17] known as the First Energy Package.

[17] European Union 1996 *Directive 1996/92/EC of the European Parliament and of the Council of 19 December 1996, concerning common rules for the internal market in electricity.*

3.1. Market liberalisation

The First Energy Package implemented a new regulatory framework for the electricity sector across the Member States based on the three pillars of EU energy strategy: securing an expanding supply of energy; developing a more competitive internal energy market; and encouraging, supporting and developing renewable energy sources [59]. Through market liberalisation the Directive planned to restructure (unbundle) vertically integrated monopolies, increase market competition and allow consumers choose between suppliers, to make the energy sector more cost effective and, from a strategic point of view, to best manage Europe's risk exposure to imported fossil fuels and the associated geopolitical concerns that lie therein [13]. The primary aim of the energy package (and liberalisation on the whole) was to improve social welfare across Europe [58, 106]. The First Energy Package initiated the most extensive energy market reform anywhere in the world according to Jamasb and Pollitt [15].

Most developed countries started to liberalise their infrastructural sectors from the 1980s onwards. Early movers such as Chile (1982), UK (1989) and Argentina (1992) led the way in energy market liberalisation [4, 17, 29]. While the motivation behind market reform differed between countries, they generally showed a desire to make the energy sector more cost effective by increasing efficiency within the wholesale and retail markets through the privatization of previously state-owned assets and introducing competition[18] [11]. Other drivers of market reform also exist, such as a political ideology based on the faith of market forces and a dislike for resilient labour unions,[19] and the wish to attract foreign investment

[18] Norway is a notable exception to this statement as they implemented market reform based on environmental policy rather than to make their energy sector more cost efficient [107].

[19] Prime Minister Margaret Thatcher's support for restructuring the state-owned Central Electricity Generating Board in England and Wales [108].

[16, 24, 35, 108]. Nevertheless, in a sector with high capital costs and long lead-times, questions remain as to whether a fully open and competitive market provides the necessary incentives for companies to invest in new plants when infra-marginal rents are continually being squeezed.[20] Ambiguity also remains as to whether reform leads to lower prices at all, as alluded to by [6, 12, 14, 19, 20, 31, 33, 35, 36, 77]. Consequently, the suitability of the textbook model approach to market reform has been discussed extensively by [10, 21, 22, 28, 29, 34, 109].

3.1.1. Market reform in Ireland

Prior to reform, the ESB operated an electricity market in Ireland that was completely internalised within the organisation. With ESB Power Generation generating to meet the demand of its supply arm; ESB Customer Supply, in what could be described as a monopolistic state. When examined by the EU Competition Commission it was concluded that "*The current structure of the Irish electricity market is not favourable to competition*." [26, p.27]. This draws attention to the fundamental concern of a monopoly where in theory, a legacy firm can pass the true cost between its generation and supply departments allowing possible perverse behaviour.[21] Moreover, FitzGerald et al. [1] highlight that Ireland has a history of promoting the interest of producers over consumers, an observation that endorses the Commission's findings.

On the other hand, a report compiled by IPA Energy Consulting [111] for the Northern Ireland Department of Enterprise Trade and Investment and the Republic of Ireland

[20] The UK's decision to introduce a capacity market for the first time in 2014 is a prime example.

[21] It should be noted that there was "*no significant market power exercised*" in Ireland as report by Cambridge Economics Policy Associates [110], however it has occurred elsewhere. For details of the case brought against E.ON AG by the European Commission for the strategic withdrawal of capacity in German electricity market, see: http://ec.europa.eu/competition/elojade/isef/case_details.cfm?proc_code=1_39388

Department of Public Enterprise concluded that Ireland's electricity prices (in real terms) were "*probably too low to support new, independent generation*." [111, p.14]. However, these low prices may be explained by the legacy monopolist improving its overall generation efficiency in anticipation of market reform through the Cost and Competitiveness Review programme that yielded net annual cost savings of IEP £90 million (€114 million) per annum[22] [113].

3.1.2. Electricity Regulation Act, 1999

The First Energy Package was transposed into national legislation as the Electricity Regulation Act, 1999 (ERA 1999). ERA 1999 transformed Ireland's electricity sector by outlining plans to: establish a national regulatory authority to oversee the transition to a liberalised market, Commission for Electricity Regulation (CER);[23] form an independent system operator responsible for operating the transmission network, EirGrid and; open the wholesale and retail markets to competition. These changes provided the backbone of market reform in Ireland; aiming to create an environment conducive to competition in the near future [26].

3.1.3. Market changes

Since February 2000 Ireland's electricity markets, both wholesale and retail, have been open to competition. The ESB's market share went from owning and operating 95%[24] of the

[22] This behaviour from incumbents was also seen in Brazil, US, and the UK [18, 25, 76, 112].

[23] Later changed to the Commission for Energy Regulation when it was appointed the regulator for other services.

[24] The remaining 5% was made up of small scale generation [26].

installed generation capacity in Ireland to 51% in 2015.[25] This was assisted by independent power producers entering the market and a CER-ESB agreement to sell off generation assets [114, 115]. The retail market also experienced change as approximately 400 large users[26] of electricity could choose between suppliers in the first year. The ERA 1999 also provided third party access to the electricity network to 'green' (wind power and other sources of renewable energy) electricity suppliers to sell directly to *all* final customers, irrespective of the customer's consumption [52], unlike 'brown' (fossil fuel based) electricity suppliers who could initially sell only to the aforementioned large users. This market opening for green suppliers was particularly important for the sections of the market that pay most for electricity (commercial and domestic customers). This provided wind farm developers with an alternative to the government support scheme route to the market.

In 2002 and 2004 the 'brown' electricity market was opened further, increasing to 40% and 56% respectively with full liberalisation occurred in 2005. The CER decided to regulate the ESB Customer Supply electricity price to reduce their market share to or below 60% in the Domestic and 50% in Business markets. Full deregulation of the retail electricity market was achieved in 2011 [116].

The structure of the wholesale market also changed with reform. While ESB Networks retained ownership of the transmission and distribution networks (operating the latter), complete control of the transmission network was afforded to the Transmission System Operator (TSO) with the enactment of the ERA 1999.[27] In terms of the market mechanism,

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[25] Installed generation capacity information retrieved from the CER's validated PLEXOS model, available at: http://www.cer.ie/

[26] Defined as a user consuming over 4 million kWh per annum. Large users represented 28% of the market.

[27] The Act obliged the asset owner to maintain and expand the transmission network as the TSO requires, pending approval from the CER.

the TSO continued to operate a bilateral contracts model as pre-liberalisation except with an interim electricity trading arrangement called a Top-Up and Spill mechanism included. Top-Up and Spill was a means of balancing long or short markets. Under this type of arrangement, the incumbent provides Top-Up and Spill services within their jurisdiction. The price of top-up services over the year was regulated by the CER based on the estimated cost of a Best New Entrant.[28] The spill costs reflected the incumbent's avoidable fuel cost.

Policy and regulatory responsibility in the market were shared by the Department of Enterprise, the Competition Authority, and the CER. The Department outlined policies to be implemented, which were often passed down from the EU, the Competition Authority analyses the market for instances of market power exertion or predatory behaviour,[29] and the CER governed the day-to-day running of the sector. The Trading and Settlement Code was an important document published by the CER during this period which outlined rules for market operation as well as for trading and settlement that underpinned the transparency and credibility which Ireland's electricity market is, still to this day, known for[30] [2, 117].

3.2. Transitioning towards an EU internal electricity market

Once the Second Energy Package, EU Directive 2003/54/EC,[31] was adopted in June 2003 the pathway for a European internal electricity market became more crystallised [17]. Where its

[28] Best New Entrant is calculated based on the infra-marginal rent necessary for a unit to recoup their capital costs.

[29] In 1998 the Competition Authority objected to an ESB lead 'Optisave Contract' initiative (for large customers) which required the customer that wanted to switch suppliers (due to lower prices) to provide details of the offer and allow an opportunity to match the offer. The contract stipulated that the customer would only be allowed leave if ESB CS could not match their competitors offer, and then only after six months' notice of termination [26].

[30] The CER also approved the TSO-lead implementation of Grid Code requirements for market participants relating to the material technical aspects of their plants.

[31] European Union 2003 *Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003, concerning common rules for the internal market in electricity and repealing Directive 96/92/EC.*

predecessor had shortcomings relating to market dominance and the possibility of perverse gaming behaviour, the Second Energy Package sought to implement a level playing field for all participants alike by ensuring non-discriminatory rights of access to the network and the publication of the basis for tariffs [70]. After liberalisation, the next step was regional fragmentation; a mid-step on the path to full implementation of an internal market which involved grouping markets based on their geographical proximity to one another. The concept was supported by the European Commission as it acknowledged the reduced complexity in coupling regional markets rather than on an individual, market by market basis [17].

Electricity market coupling started in the Nordic region with Sweden and Norway creating the first multinational electricity exchange in 1990. This exchange expanded further when Finland and Eastern Denmark joined what is known as the Nord Pool four years later [118]. On mainland Europe, electricity market coupling first took place in 2000 with the formation of the European Energy Exchange, which later expanded outside of Germany when the French and Austrian markets joined to form the EPEX Spot market [119]. After Ireland's electricity market was reformed, a steering group was set up with representatives from Ireland and NI to assess the possibility of coupling the two markets. In 2004 the respective Regulatory Authorities[32] (RAs) from both jurisdictions signed a Memorandum of Agreement relating to a new market structure which, in 2005, was followed by legislation to underpin the All-island Single Electricity Market.[33]

[32] Consisting of CER from Ireland and the Northern Ireland Authority for Utility Regulation from Northern Ireland.

[33] The Electricity Regulation (Amendment) (Single Electricity Market) Act 2007 in Ireland and the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 in Northern Ireland [120].

3.2.1. Regional fragmentation

The All-island Single Electricity Market (SEM) was established in November 2007 as the central trading platform for electricity on the island of Ireland. Costing approximately €110 million, this cross-jurisdictional centrally-dispatched gross pool market with dual-currency is fully liquid, due to its mandatory nature for generators and suppliers [121].

All generators above the De Minimis 10MW capacity level bid into the day-ahead market using their short run marginal cost which accounts for fuel, carbon and variable operation and maintenance costs, for delivery the following day. Bids are stacked and dispatched based on a merit-order curve that commits the lowest cost generators first, followed by more expensive units until the demand is met. The market employed a 'pay-as-clear' or 'marginal pricing' model, therefore the last successfully cleared generator in a trading period sets the System Marginal Price (SMP) which all dispatched plants receive, and suppliers pay.[34] Dispatch schedules can change after the economic dispatch has been complete due to transmission constraints and ancillary service requirements.[35]

For generators in the SEM, it offers a platform to sell their product with little or no risk exposure. For example; if a generator is constrained on but cannot recoup their fixed costs, then an adder called an 'Uplift' is included in the SMP to cover their costs. Similarly, if a unit has not earned enough infra-marginal rent to cover their fixed costs then a 'Make Whole Payment' is made to the generator to ensure a net balance of zero over a week-long period. Make Whole Payments, constraint payments, and imbalance charges are recovered from suppliers through an Imperfection Charge that is passed on to the end-user. There is also

[34] Suppliers also pay other system charges and levies for network and obligatory requirements as judged necessary by the CER.

[35] For details of network constraints and ancillary service requirements, along with information on constraint payments, see: http://www.eirgridgroup.com

insurance on fixed cost recovery over the longer term through a capacity payment mechanism which as with its predecessor–the capacity margin scheme[36]–was introduced to ensure adequate installed generation capacity. The annual capacity 'pot' is set by the RAs using the previously mentioned Best New Entrant methodology.[37]

In terms of market structure and overall governance, some changes occurred with the introduction of SEM. For example, the RAs introduced the Bidding Code of Practice to restrict bidding strategies and eliminate opportunities for predatory behaviour by market participants.[38] This, along with other existing market codes such as the Trading and Settlement Code and Grid Code were monitored through the Market Monitoring Unit to ensure compliance and that no market power was exerted. Implementing market rules and general market operations are carried out by the single electricity market operator which is a joint venture between both TSOs.[39] Otherwise, the structure remained the same as pre-SEM

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[36] The capacity margin scheme was introduced in 2001 as the margin between installed generation capacity and peak demand had eroded, as shown in Figure 3. Over this period, Ireland experienced large economic growth and forecasts showed continuous increases in demand over the following years. To ensure adequate levels of generation capacity were installed a capacity mechanism was introduced in 2001 to encourage new investment in Ireland's electricity sector by increasing the certainty of recouping capital costs [122]. Generators benefitted from the scheme if their unit was available when capacity margins were tight. In these instances, the generator received an additional revenue stream that was mutually exclusive to any infra-marginal rent earned [123]. The associated cost was recouped from customers through the Transmission Use of System charge; a new addition to the standard electricity bill under the ERA 1999 [122].

[37] Revenue earned by generators in SEM from energy, capacity and constraint payments between 2008-2015 was 75%, 20%, and 5% respectively [124].

[38] Cambridge Economic Policy Associates when reporting on market power and liquidity on behalf of the RAs, found that the Bidding Code of Practice has been an effective mitigating factor of market power [110].

[39] EirGrid in the Republic of Ireland and their counterpart System Operator of Northern Ireland in NI. EirGrid acquired their Northern Irish counterpart in March 2009.

with ESB Networks[40] retaining ownership of the transmission and distribution networks, operating the latter with the TSO controlling the former.

3.3. The EU Target Model

The EU Target Model for electricity emerged from the Florence Forum process in 2009 as a blueprint with both top-down and bottom-up guidance on the future market design deemed necessary to facilitate the EU integrated internal market for electricity [61]. Aligned with the three energy packages,[41] the model outlines the necessary approach to full market integration using clear rules for implementation (network codes[42]), market coupling initiatives (multi-regional coupling) along with structuring the necessary power exchanges and systems to operate the various power markets (i.e. forward, day-ahead, intra-day, balancing markets) [125].

The primary aim of the Target Model is to maximise social welfare gain for all market participants, i.e. maximise consumer and supplier surpluses. Using the “copper plate” effect outlined by Barroso et al. [60], the internal market is based on a principle where electricity generated in one area is consumed in another without geographical or market-based constraints–causing a price equilibrium across the region. It was acknowledged by the European authorities that for this to transpire, full utilisation of interconnection capacity between price zones was vital for any future integration plans. This barrier was addressed in

[40] ESB Networks along with ESB Electric Ireland (replaced ESB Customer Supply) and ESB Generation and Wholesale Market (replaced ESB Power Generation) became legally separate entities in February 2009 as part of the unbundling process outlined in the EU energy packages.

[41] The Third Energy Package: European Union 2009 *Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009, concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC.*

[42] Network codes were developed by the European Commission, Agency for Energy Regulators and the European Network of Transmission System Operators to provide guidelines for the internal energy market to trade energy [125].

the Capacity Allocation and Congestion Management[43] network code that promotes economically-driven power flows on interconnectors which, as pointed out by McInerney and Bunn [127], has not always occurred. By lowering technological and institutional barriers, such as the previous example, electricity markets across Europe could be fully coupled as has been the case in the Nordic region since 1990 [118].

3.3.1. The Integrated Single Electricity Market

The SEM is known for its transparency and as a highly functional, effective pool-based market that works in the interest of consumers according to Gorecki [76]. Nevertheless, it must transform to comply with the Third Energy Package. After receiving various derogations on implementing the Target Model due to its unique situation of being an "*island system with central dispatch*" [87, Section 1.2], SEM must become compatible with the greater European electricity market in 2018.

Transforming SEM to become compatible with electricity markets across Europe involves restructuring its forward, day-ahead, intra-day, and balancing markets. Notwithstanding the fact that the new version of SEM, known as the Integrated Single Electricity Market (I-SEM), will remain centrally dispatched, it will also be more onerous on market participants in terms of hedging risk exposure through forward contracting and implementing bidding strategies. In I-SEM the aforementioned safeguards to risk exposure, i.e. Uplift and Make Whole Payments, will no longer exist, therefore participants need be more active in both forward and intra-day market trading; neither of which are currently very liquid in SEM. Add in a new

[43] For more details, see the Capacity Allocation and Congestion Management Report from the European Network of Transmission System Operators for Electricity (ENTSO-E) which outlines Network Codes for use in the internal market [126].

suite of system services[44] along with the latest iteration of a capacity mechanism based on financial options,[45] and Ireland's electricity market is set to evolve from what was a straightforward bilaterally traded energy market into the multidimensional, complex instrument.[46,47]

4. The role of climate mitigation policy

In addition to the EU energy packages, EU climate mitigation policies on renewable energy, greenhouse gas emissions reduction and air pollutant limits also impacted on the electricity sector as the Member States were required to make a concerted effort to be sustainable. For instance, the EU Directive 2001/77/EC[48] established a target for Ireland to achieve 13.2% of gross electricity consumption from renewable energy sources by 2010. Similarly, the 2020 Climate and Energy Package set three targets for 2020 for the EU: to achieve a 20% renewable energy share of gross final consumption; to reduce greenhouse gas GHG emissions by 20% compared to 1990 levels and; to improve energy efficiency by 20% compared to 2005 levels. The renewable energy target from the Climate and Energy Package was

[44] The "*DS3 - Delivering a Secure, Sustainable Electricity System*" programme strengthens, and doubles the number of, ancillary services in place to fourteen. DS3 aims to facilitate increased levels of variable renewable generation on the island of Ireland to ensure compliance with Article 16 of Directive 2009/28/EC (duty to minimise curtailment of renewable electricity), helping to reach binding Member State renewable energy targets by 2020. For more information, see: [128].

[45] The Capacity Remuneration Mechanism as it is known, will take the form of a volume-based reliability options mechanism that operates in a similar way to a financial call option or one-way contract for difference. For more information, see: [129-131]

[46] See the following decision papers from the RAs for further details: [129-134].

[47] This market evolution may turn out to be a big winner for software development houses as was the case in Britain with the implementation of the New Electricity Trading Arrangements in 2001 which ended up far over budget costing approximately US$2 billion, according to Thomas [33].

[48] European Union 2001 *Directive 2001/77/EC of the European Parliament and of the Council on the Promotion of Electricity from Renewable Energy Sources in the Internal Electricity Market.*

subsequently transmitted into individual Member State targets in EU Directive 2009/28/EC.[49] To achieve Ireland's 16% target, the government set individual sectoral targets for renewable electricity (40%); renewable heat (12%) and renewable transport (10%). The 2010 and 2020 targets for renewable electricity have driven the acceleration of wind farm deployment in Ireland, supported through market support mechanisms.

The EU greenhouse gas emissions target was separated into two separate targets. EU Directive 2009/29/EC[50] on emissions trading set a target of 21% reduction by 2020 relative to 2005 levels for large point source emitters who are in the EU Emissions Trading Scheme (ETS) and a 10% reduction by 2020 relative to 2005 levels for those outside of the ETS, i.e. the non-ETS sectors. Electricity generation falls within the ETS, as most power plants are considered large point source emitters. The ETS price has been lower than anticipated and questions have been raised about its effectiveness by Muúls et al. [135].[51] However, the ETS may have led to higher investment in carbon-neutral generation capacity. The non-ETS target has no direct impact on electricity and was distributed amongst the Member States per Decision number 406/2009/EC.[52,53]

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[49] European Union 2009 *Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources*

[50] European Union 2009 *Directive 2009/29/EC of the European Parliament and of the Council of 23 April 2009 amending Directive 2003/87/EC to improve and extend the greenhouse gas emission allowance trading scheme of the Community.*

[51] ETS reform is currently underway. The aim is to raise the price to a "cost-effective emission reductions" level that would impact on fossil-fuel based generating plants and their marginal cost of generation. ETS reform could bring about the goal of the ETS and introduce a carbon tax that will reduce the amount of emissions gradually over time, eventually leading to decarbonisation. For more information, see: [136]

[52] European Union 2009 *Decision No 406/2009/EC of the European Parliament and of the Council of 23 April 2009 on the effort of Member States to reduce their greenhouse gas emissions to meet the Community's greenhouse gas emission reduction commitments up to 2020.*

[53] An air pollution target was published in the EU National Emissions Ceiling Directive (Directive 2001/81/EC) which set upper limits for each Member State for the total emissions in 2010 (currently being revised to extend limits to 2020) of the four pollutants responsible for acidification, eutrophication and ground-level ozone

4.1. National climate mitigation policies

Support for renewable electricity in Ireland was first introduced in the 1990s. While the Alternative Energy Requirement (AER)[54] support scheme was started in 1994, it was not until a government policy in 1996 entitled "Renewable Energy – A Strategy for the Future" that a framework was implemented to address climate mitigation measures.[55] This policy played a large role in developing the Irish wind energy sector due to the inclusion of wind energy targets up to 2010 [137]. Furthermore, in 1997 ESB International estimated the potential from wind power in Ireland to be in the range of 345TWh per year or in other words, more than 19 times the national demand of the time [46]. This provided a clear impetus for policy support surrounding wind power as it could increase the nation's security of supply.

Climate mitigation policies continued to support the development of Ireland's wind energy sector, showing year-on-year growth. For instance, the "Green Paper on Sustainable Energy" published in 1999 set an ambitious target to install 500MW of renewable energy capacity nationwide between 2000-2005. The paper outlined plans to reform the AER scheme, improve measures supporting the deployment of renewable energy, while also providing concrete proposals for market liberalisation and becoming a central feature in Ireland's greenhouse gas abatement strategy [47]. This was followed by the introduction of Renewable Energy Feed-in Tariff (REFiT) in 2006 to replace the AER scheme to further expand the sector. Through centrally administered price setting, the REFiT programme sought to

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pollution (sulphur dioxide, nitrogen oxides, volatile organic compounds, and ammonia). This prompted investment in flue gas desulphurisation (reducing SO_2) and selective catalytic conversion (reducing NOx) at the Moneypoint power station in 2010.

[54] The AER was a competitive bidding process supporting alternative energy sources through a power purchase agreement of up to 15 years in duration [47, 55].

[55] The main justification for the strategy was for 'security of supply' purposes. It was estimated that without developing renewables, the electricity generated from indigenous energy sources would drop from 43% in 1994 to 8% by 2011 [137].

increase the profitability of wind power which, according to Global Wind Energy Council & International Renewable Energy Agency [47], had led to many projects not being developed as a result of low prices received under the AER competitive bidding process. Figure 3 demonstrates the success both support schemes achieved in terms of promoting wind power in Ireland.

4.1.1. Pecuniary externalities influencing market dynamics

In Ireland, the AER and REFiT support schemes are funded through a Public Service Obligation (PSO) levy that was introduced in 2003 as a means of ensuring 'security of supply' and supporting indigenous and renewable fuel sources outside of the market[56] [138]. The levy affords units qualifying under the indigenous fuels or renewable sources categories priority dispatch in the energy market and is a prime example of a 'pecuniary externality' directly affecting the electricity market in Ireland. The three categories eligible to receive a power purchase agreement under the levy are as follows:

- **Indigenous fuels:** Three peat-fired plants with a combined installed capacity of 378MW[57]
- **Renewables:** The renewables capacity supported in the 2015/16 PSO levy was 2210MW
- **Security of supply:** Over 200MW of open cycle gas turbine "peaking" capacity was afforded power purchase agreements. A 400MW combined cycle gas turbine plant and

[56] The RAs forecast the overall PSO cost for the following year and set the consumer levy accordingly. Ex-post calculations are carried out after the PSO year (Oct 1st to Sept 30th) has concluded to quantify any variances between forecasted and actual costs, and if necessary reconciliation is performed when calculating the levy for following year.

[57] The International Energy Agency estimated the cost of generating electricity from peat in 1999 to be 50% higher than if using coal. It was also pointed out that subsidies in Ireland for peat were far lower than for coal in other EU Member States, such as Germany or Spain [139]. Supporting peat for electricity generation also has socio-economic advantages in terms of local employment in areas of Ireland which are below the average employment rate [26].

160MW combined heat and power plant were awarded agreement in 2005, referred to as "Cap '05" [140]

Figure 4 shows the distribution of the total PSO levy costs (€1.59 billion) from its introduction in 2003 to the forecasted levy for the 2015/16 PSO year. The indigenous fuels category (peat) accounts for the largest share of 48%, with renewables accounting for 28% and Cap '05 accounting for 17%. Peaking and Others (administration costs) account for the remainder.

[Insert Figure 4]

Implementing a competitive market should, ideally, limit external influences on the market, leaving costs directly associated with the product the only driver of market price, i.e. fuel and variable operation and maintenance costs. However, as awareness of environmental concerns become more prevalent and the realisation that security of supply and reliance on imported fuels are vital to economies, this may fail to materialise as some external costs are not internalised in the price of electricity. The PSO levy is a prime example of a pecuniary externality and when taken along with other external influences such as the 1970s oil crises or issues around the public acceptance of nuclear energy for example, have influenced change in the generation portfolio, as described in Section 2 and illustrated in Figure 3.

Moreover, from a market perspective, some externalities can distort entry and exit market signals. Take for instance a market based on economic dispatch; priority dispatch and renewable energy support are two influencers that can destabilise the foundations on which the market functions [79]. When a market contains high levels of zero-marginal-cost power sources (e.g. wind or solar-based generation), the resulting SMP would be lower than if these were not included due to the 'merit order effect' as shown by [40, 41, 54]. Generally, lower SMPs do not affect zero-marginal-cost power sources in the same way as it would for other plants due to support mechanisms in place. However, if infra-marginal rent cannot be obtained for a 'traditional' thermal unit then fixed costs cannot be recouped without some addition mechanism such as an Uplift, Make Whole Payment or capacity payment mechanism as occurs in SEM. This aspect of market design has been recently discussed in reports by [29, 54, 79] who outline a range of issues that face modern day electricity markets. Keay [79] concludes that electricity markets in Europe may effectively be broken and questions how they must evolve to be fit for purpose again, while Sen et al. highlights the need for "*renewed thinking, or a shift in focus – in other words, a 'reform' of electricity reform*" [29, p.39]. This concern goes beyond the borders of this paper and therefore not addressed in further detail.

4.1.2. Outlook for Ireland's electricity sector

A recently published government policy called "Ireland's Transition to a Low Carbon Energy Future 2015-2030" may shape the electricity sector of the future in Ireland [141]. Aiming to transition towards a low carbon energy system while maintaining the three core objectives of sustainability, security of supply, and competitiveness, the focus of the paper is on achieving the optimal benefits at least cost to consumers through new frameworks and pathways, consumer interaction and by promoting innovation and enterprise opportunities. From a broader perspective, the ETS reform may have the desired effect and increase the marginal cost for fossil-fuel based units in Ireland and across Europe to generate power. And finally, the various out-of-market payments made possible through EU energy policy will continue to affect market dynamics; raising concerns around its suitability to the generation portfolio of the future.

5. Conclusion and policy implications

This paper highlights the role of policy in Ireland's electricity sector over the past 100 years. Numerous key transitions occurred over the period that were directly associated with policy decisions. For example, the decision to create a state-owned entity to operate, manage and maintain the sector and distribute electricity nationwide on a non-profit-making basis. In a move that would have a significant effect on the future of the sector, the ESB turned down the option of selling electricity in bulk to other distributors, instead opting to deliver electricity directly to consumers to reduce the effects of local politics and municipal boundaries on the development of a national electricity network.

Another example was the lack of policy direction in the 1950s/60s that left the nation exposed to the 1970s energy crises; exposure which resulted in a renewed focus in Irish energy policy. With the aim of increasing security of supply, Ireland attempted to reduce its reliance on imported commodities (i.e. oil) by diversifying the generation portfolio through the promotion of coal, peat, natural gas and later, wind power. Furthermore, through support mechanisms and renewable energy targets that stemmed from climate mitigation policies and security of supply ambitions, Ireland used energy policy to achieve one of the highest penetrations of variable renewable generation (wind power) in the world. Therefore, poor policy direction in one period of time provided the impetus for strong energy policy afterward.

Ireland is subject to EU legislation and through the energy packages enacted in 1996, 2003 and 2009, three distinctive phases of market transformation were initiated. First, market liberalisation occurred and had an immediate, even a pre-emptive, effect as the legacy monopolist improved overall efficiency in its preparations for the open market. Second, a new cross-border, multi-currency electricity market was created. Referred to as the all-island single electricity market (SEM), this market was found to work in the interest of consumers due to its open and transparent nature. Then again, it could also be said that the new market worked well for market participants, specifically generators, as mechanisms were in place to ensure cost recovery. Third, the final market transformation to comply with the EU Target Model; joining Ireland's electricity market to the rest of Europe. This market overhaul created I-SEM, a version of the previous pool-based market that had been shoe-horned to ensure compatibility with the regional alternative. However, as described by Gorecki; "*Aligning SEM with the Target Model appears very much to be a matter of fitting a square peg into a round hole.*" [76, p.687]. I-SEM may be described as a complex multi-dimensional instrument that exposes market participants to heightened financial risk when compared to its predecessors.

EU climate mitigation policies on renewable energy, greenhouse gas emissions reduction and air pollutant limits have changed the electricity sector significantly as the Member States were required to make a concerted effort to be sustainable. The various pecuniary externalities, such as out-of-market payments for example, will continue to affect market dynamics; raising concerns around the suitability of the modern-day market to adapt to the generation portfolio of the future. However, this concern goes beyond the boundary of this paper and may require further research later.

Broadly speaking, the evolution of Ireland's electricity sector was in some way synonymous with developments in other countries. Increasing security of supply was key after the 'awakening' provided by the oil crises. In Irelands situation as an island state with little (electrical) interconnection, the learnings provided by this paper regarding policy decisions surrounding the decision to create a non-profit state-owned entity, security of supply and the development of wind power should be useful for policy makers in developing nations faced with similar decisions as the 'barriers/mistakes/shortcomings' that confronted Ireland over the 100 years of evolution are highlighted.

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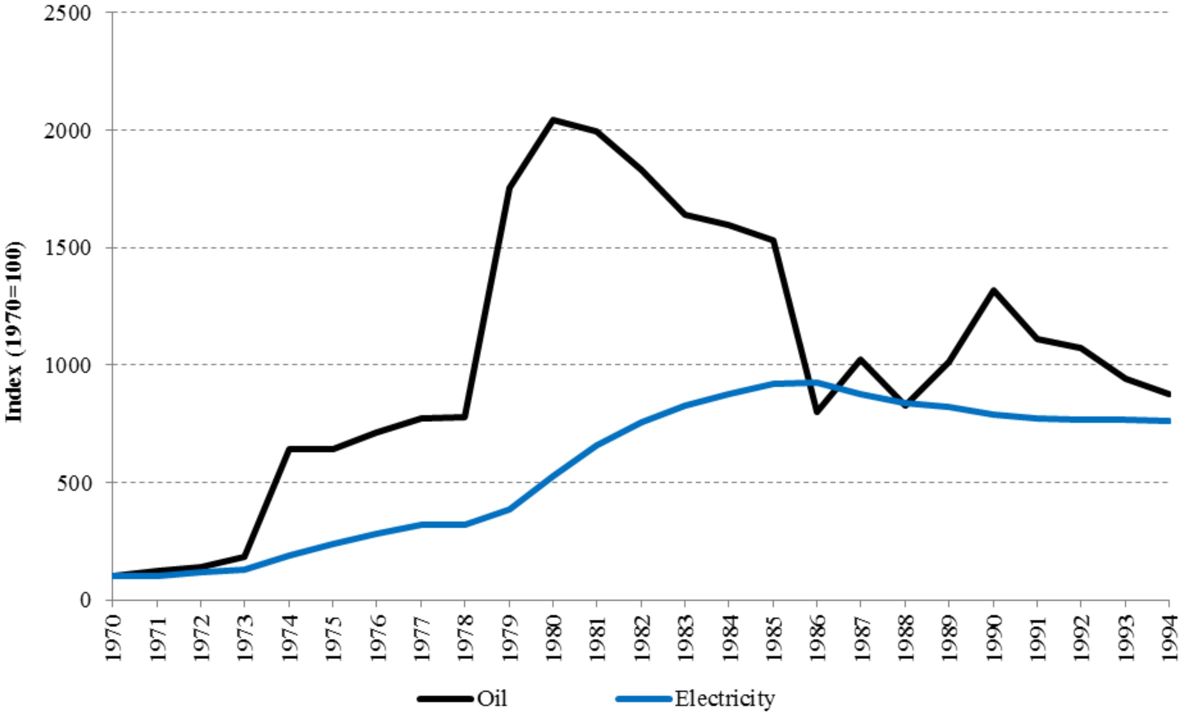
Figure(s)

Figure 1: Ireland's transmission system in 1930

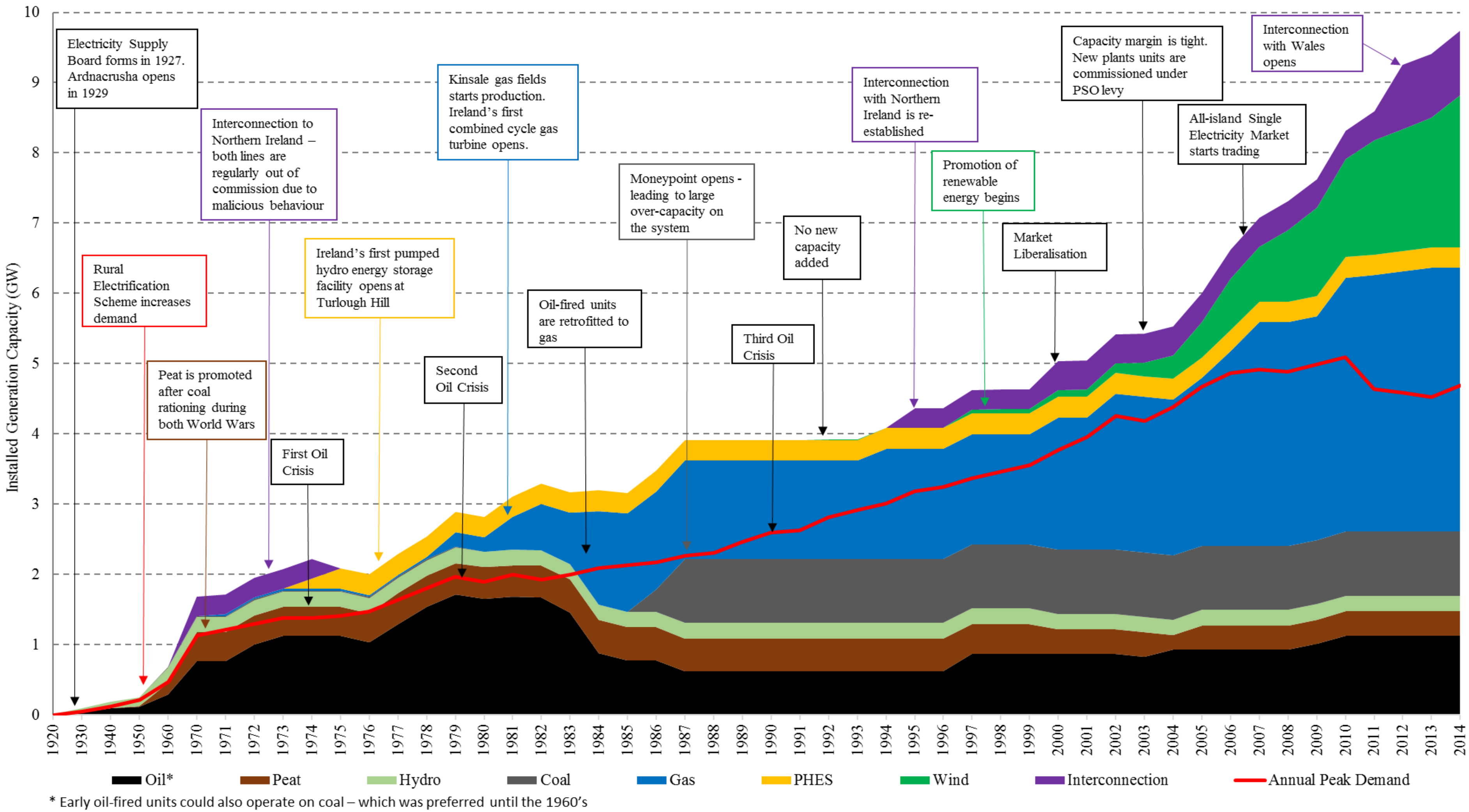
Source: Development of Ireland's Power System 1927-1997 [3].

Figure 2: Evolution of global oil price and domestic electricity price in Ireland



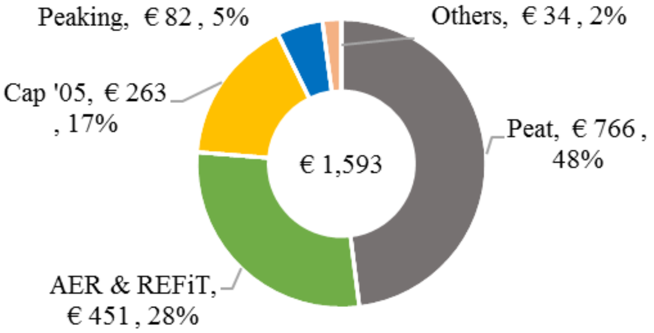
Source: Oil prices retrieved from British Petroleum, Statistical Review of World Energy 2015 [99]; Domestic electricity price retrieved from ESB Archives, Dublin [95].

Figure 3: Total installed generation capacity and annual peak demand in Ireland



Source: Sustainable Energy Authority of Ireland, Energy Balance, Dublin [104]; ESB Archives, Dublin [95].

Figure 4: Disaggregated total cost of the PSO levy between 2003 and the 2015/16 PSO year (€millions)



Source: Commission for Energy Regulation, PSO Levy Annual Reports, Dublin.