DECOUPLING UTILITY SALES AND REVENUES

Country/region	**United States, EU**
Type of E1st approach	A – In front / General 2 – Enabling E1st (Regulation)
Energy carrier(s) targeted	Natural gas, electricity
Sector(s) / energy system(s) or end-uses targeted	Generation / transmission / distribution
Implementing bodies	Regulators/governing boards, utilities
Decision makers involved	Utilities
Main objective(s)	Remove disincentives for regulated electricity and natural gas utilities to promote energy efficiency and other demand-side resources
Implementation period	1982 – ongoing

Utilities are responsible for providing customers with reliable and reasonably priced energy services. However, under traditional regulation, utilities – such as electricity and gas network operators – are discouraged from investing in cost-effective energy efficiency because it lowers their revenues. An established way to remove this conflict is to break the link between the utility's revenue and the amount of energy it sells or transmits in order to ensure that the utility recollects its capital expenditures and operating expenses plus an authorised return on investment, no less and no more. In combination with other regulatory mechanisms, such decoupling mechanisms can induce utilities to help customers save energy whenever it is cheaper than producing and delivering it (Sullivan et al., 2011).

1. Background

In traditional utility regulation, the regulator (for investor-owned utilities) or governing board (for publicly-owned utilities) determines the amount of revenue the utility needs to collect from customers to recover its costs of maintaining and investing in the system's wires, pipes and generators – including, for investor-owned utilities, a reasonable return on investment. The regulator or governing board then divides this authorised revenue by the amount of energy it expects consumers to consume, and establishes a tariff ($/kWh) (NRDC, 2012). These tariffs are then part of the price customers pay per unit of electricity or gas used. With the tariffs set, the utility's actual revenue depends on the amount of energy customers use, i.e., sales (NARUC, 2007).

Setting tariffs is conducted every few years in so-called tariff proceedings. Between proceedings, utilities' ability to recover their costs is based on sales (NARUC, 2007). While the extent of energy use is anticipated in the tariff proceeding, actual sales will almost always differ due to complex variables (e.g., weather, changes

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 839509. The sole responsibility for the content of this website lies with the authors. It does not necessarily reflect the opinion of the European Union. Neither the EASME nor the European Commission are responsible for any use that may be made of the information contained therein.

in economy, demographic shifts, new end-use technologies). As a result, the utility will either earn more or less on electricity and gas than had been assumed during the tariff proceeding (NARUC, 2007). When sales are higher than anticipated, utilities may collect more revenues than their expenses and reasonable return, leading to increased profits.[1] This reflects a throughput incentive for the utility, i.e., increased sales leading to increased profits. In turn, it is a disincentive for utilities to invest or engage in anything that decreases sales, such as energy efficiency programmes, distributed renewable energy generation and other demand-side resources – even if these are cost-effective to meet customer needs (NRDC, 2012). The throughput incentive does not only contribute to utility inaction on energy efficiency, there are cases where utilities have actively countered efficiency measures in their service area to promote sales (Sullivan et al., 2011).[2]

Overall, under this traditional regulation, the customer loses in two ways. When sales fall, the utility may not recover all its costs and will have to go through costly litigated regulatory proceedings to do so, which customers pay for. When sales increase, utilities may collect more than their authorised costs and reasonable return, creating windfall profits at customer expense. In either case, customers lose the economic benefits they would have enjoyed if the utility invested in cost-effective demand-side resources (NRDC, 2012). Regulators can solve this problem by implementing decoupling mechanisms that adjust tariffs to ensure a utility collects the costs its regulator or governing board authorises, no less and no more. Combined with other regulatory policies, such decoupling mechanisms can free utilities to help customers save energy whenever it is cheaper than producing and delivering it (NRDC, 2012).[3]

In practice, decoupling does not change the traditional tariff proceeding procedure but, in its simplest form, adds an automatic adjustment to tariffs between tariff proceedings based on over- or under-recovery of authorised revenues. Similar to traditional tariff proceedings, tariffs are set by determining the revenue requirement and dividing by expected sales. Then, on a regular basis, tariffs are re-computed to collect a target revenue based on actual sales volumes.[4] This means that if sales increase, tariffs drop in the next period; if sales decrease, tariffs increase to compensate. Overall, these regular tariff adjustments between tariff proceedings break the link between (or *decouple*) a utility's revenue and sales by either restoring to the

[1] The underlying assumption being that for existing customers, sales growth does not require a great deal of new infrastructure (e.g., generators, transmission and distribution lines, substations). In these cases, utilities' fixed costs would not increase with increased sales, thus translating into increased profits (NARUC, 2007).

[2] Measures pursued by utilities include a) providing incentives for the use of inefficient equipment or practices, such as electric resistance heat, b) opposing highly cost-effective efficiency codes for new buildings, c) failing to include energy efficiency in their communications with customers (Sullivan et al., 2011).

[3] Decoupling is only one mechanism within a broad portfolio of regulatory mechanisms subsumed under the term performance-based regulation (PBR). Broadly speaking, PBR provides utilities with a regulatory framework that encourages better performance, such as enhanced energy efficiency within its service area. Besides decoupling (also referred to as *revenue cap regulation*), other PBR mechanisms include price cap, incentive-based and yardstick mechanisms (Lazar, 2014).

[4] Usually, tariff reconciliations are made at least on an annual basis to compensate for under- or over-collection of fixed costs during the previous year. Note that this is different from traditional tariff-making in which there is little oversight of revenue between tariff proceedings and often several years go by before tariffs are realigned with actual revenue requirements (NRDC, 2012; Sullivan et al., 2011). For example, tariff proceedings for California's Pacific Gas and Electric Company are only held every three years (Midgen-Ostrander et al., 2014).

utility or giving back to customers the money that was under- or over-collected as a result of fluctuations in retail sales. This ensures that utilities (NRDC, 2012):

- recover only the costs that were approved by their regulator or governing board.
- cannot make windfall profits by encouraging higher sales.
- are not penalised when demand-side efforts reduce sales.

All in all, decoupling mechanisms can remove disincentives for regulated utilities to promote energy efficiency and other demand-side resources, but they are not designed to provide actual incentives since they provide lost margin recovery, not a reward (Lazar, 2014). To provide distinct incentives for the update of energy efficiency and other demand-side resources, decoupling needs to be part of a package of regulatory policies. Most notably, this includes a) timely and full recovery of the cost of demand-side programmes, and b) providing incentives for utilities to reward energy efficiency and ensure that investments in cost-effective energy efficiency opportunities are as attractive over time as alternative investments in infrastructures (CNEE, 2016; NARUC, 2007; NRDC, 2012; Pató et al., 2019).

2. How has the E1st principle (or similar concept) been implemented?

The idea of decoupling a utility's revenues from its sales to foster demand-side investments is not new. In fact, it has been implemented in some parts of the U.S. for decades.[5] In recent years, regulators around the U.S. have increasingly adopted decoupling mechanisms to support investment in demand-side resources (Lazar, 2014; NRDC, 2012). Figure 1 shows the status of decoupling in the 50 U.S. states as of 2019. At least 26 states have adopted some form of decoupling for electric utilities, natural gas utilities or both (NRDC, 2012).

[5] The first state to enact decoupling mechanisms was the state of California with its 1982 *Electric Tariff Adjustment Mechanism* (ERAM) issued by the state's public utility commission. The ERAM required utilities to track the difference between actual and forecasted revenues. Over-collections were refunded to consumers while under-collections were recovered by subsequent tariff adjustments (NRDC, 2012).

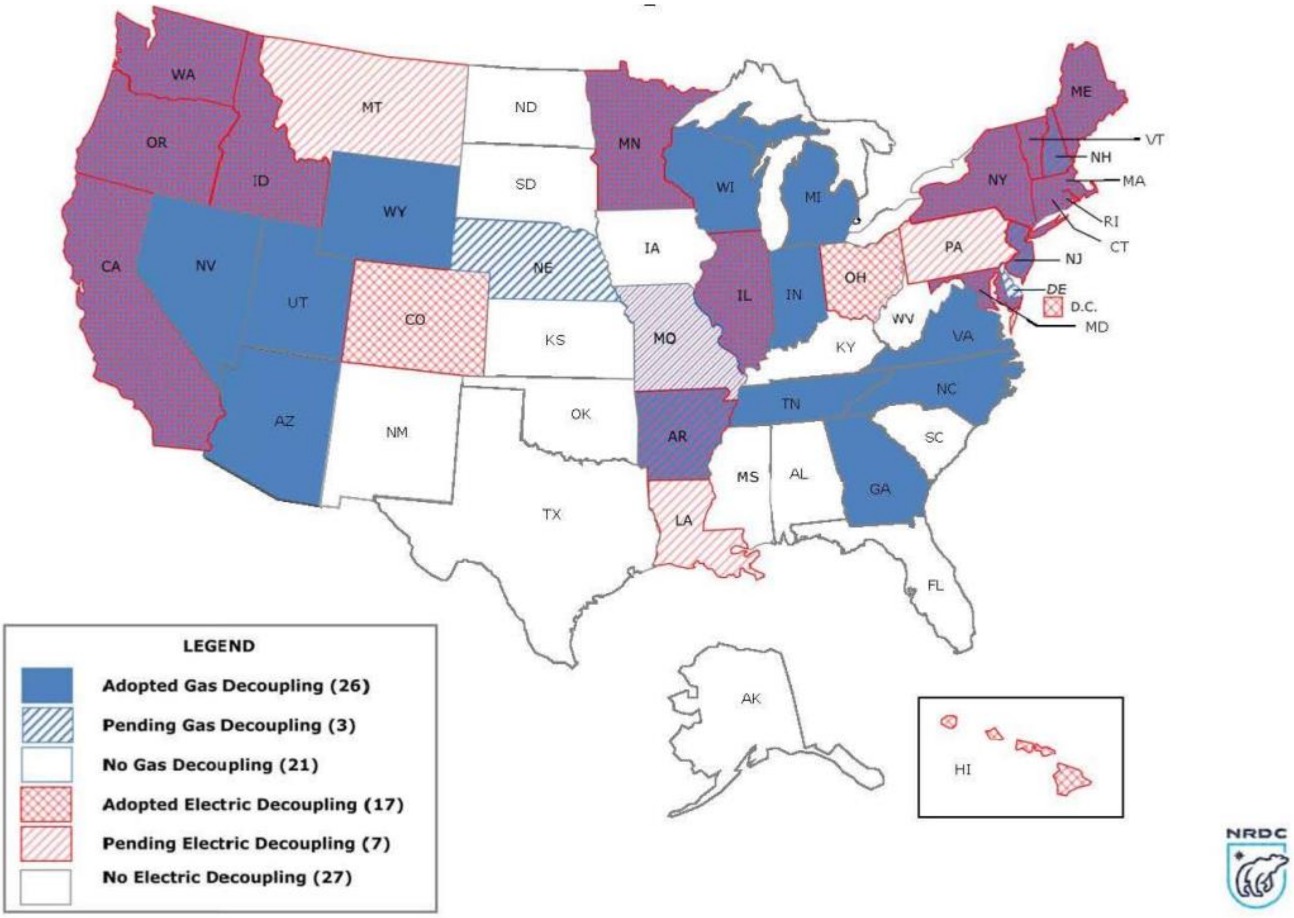

Figure 1 – Gas and electric decoupling in the U.S., as of January 2019 (Source: NRDC, 2012)

3. Effects / impacts

In general, due to their ongoing implementation over decades as well as the multitude of accompanying regulatory and financial policies, it is methodically difficult to determine the distinct effect of decoupling mechanisms on the ramp-up of energy efficiency and other demand-side resources. However, a range of observations can be made. According to Sullivan et al. (2011), in 2010, seven of the 10 U.S. states with the highest per capita investment in electric energy efficiency programmes and eight of the 10 states with the highest per capita investment in natural gas energy efficiency programmes had decoupling mechanisms in place. On another note, decoupling measures taken in the states of California, Oregon, Washington, Wisconsin, Michigan, and Hawaii and the region of New England have produced significant improvements in energy efficiency without harming the financial conditions of the utilities (Lazar, 2014).

Referring back to the example of California, utilities significantly increased their energy savings over time. Between 2001 (when decoupling and other supportive policies had been reinstated) and 2010, they increased their investments in efficiency nearly five-fold to over 3% of revenues – and achieved significant increases in energy savings. In addition to providing efficiency programmes for customers, California investor-owned utilities have been instrumental in the adoption of more stringent codes and standards at the state and federal level, including the state's TV efficiency standards that are projected to save 6,500 GWh annually by 2020 (Sullivan et al., 2011). Overall, as argued by Midgen-Ostrander et al. (2014), the implementation of decoupling mechanisms may be viewed as successful if the utility is no longer concerned about increases and decreases in sales, is no longer taking actions to increase sales or reduce decreases in sales, and is improving the overall efficiency of its operation and management.

Besides effects on energy efficiency, decoupling mechanisms have been evaluated with regard to their impact on customer bills. Experience shows that in the short run, tariffs for all customers under decoupling may increase when efficiency reduces sales because the utilities have to cover their costs and necessary returns on investment. However, any tariff increases would be small, particularly when compared to benefits for customers engaging in energy efficiency programmes. In some U.S. states evaluated (New York, California, Oregon), fluctuations in tariffs between tariff proceedings were less than 1% for most years and never exceed 4% (NARUC, 2007; NRDC, 2012). In another evaluation of decoupling mechanisms operating between 2000 and 2009 in 45 U.S. utilities, most often adjustments of less than $1.50 per month for residential gas consumers and less than $2.00 per month for residential electric customers occurred (Lesh, 2009). Overall, this is in an order of magnitude less than the size of adjustments customers regularly see from pass-throughs of fuel or purchased power costs (Sullivan et al., 2011).

4. Changes over time, if any

As stated, California was the first U.S. state to adopt decoupling. By 1982, the California Public Utilities Commission (CPUC) put decoupling in place for its three major investor-owned utilities – Pacific Gas and Electric Company (PG&E), Southern California Edison and San Diego Gas & Electric (Midgen-Ostrander et al., 2014). Although the CPUC determined that the mechanism would eliminate disincentives to promote energy efficiency and also be fair to consumers, it was suspended in 1996 as part of the state's now-infamous experiment in deregulation or electric restructuring (Sullivan et al., 2011). However, it was one of the first policies reinstated in 2001 in the wake of the Western Energy Crisis. By early 2005, every major investor-owned utility in California had decoupling in place again. As part of this, California made cost-effective energy efficiency a priority energy resource. Aggressive energy savings targets were set, complemented by a "shared-savings" mechanism providing financial incentives for utilities if they do a good job saving customers money through energy efficiency, and penalties for poor performance (Midgen-Ostrander et al., 2014; Sullivan et al., 2011).

5. Barriers and success factors

One concern related to decoupling is the question of whether it shifts risk from the utility to customers (Sullivan et al., 2011). This is illustrated by the situation in the state of Maine in the 1990s. The state had pioneered a decoupled tariff design with the utility Central Maine Power in 1991 but faced an economic recession at the same time. The recession resulted in lower electricity sales than anticipated in the tariff proceeding, with the decoupling mechanism taking effect to reflect pre-recession target revenues for the utility. This caused tariffs to go up when customers were least prepared to pay them, causing customer deferrals to accumulate steadily. As a result, decoupling became increasingly viewed as a mechanism that was shifting the economic impact of the recession from the utility to consumers, rather than providing the intended incentive for demand-side investments. Note that in this case, decoupling wasn't the problem; the economic downturn was the problem. In traditional regulation without decoupling, price increases set in tariff proceedings would have reflected the same economic circumstances, only with greater delay (NARUC, 2007; Sullivan et al., 2011). To alleviate the effects of economic downturns and other factors on sales beyond a utility's control, some U.S. states have established normalisation mechanisms that can be used to eliminate risks or assign them properly (NARUC, 2007).

Another issue with decoupling is that it can encourage utilities to take cost-cutting steps that might hurt system reliability, safety and customer satisfaction. Since decoupling tells the utility that its revenues will not be affected by sales, the only way for the utility to increase earnings is to reduce expenses and capital additions. For this reason, decoupling is generally paired with a service quality index mechanism so that any diminishment in the quality of service will be penalised (Lazar, 2014).

6. Replicability and scalability potential

In principle, decoupling mechanisms are neither difficult to design nor complex to administer. In its basic form, decoupling is simply a system of regularly adjusting tariffs to ensure a utility's actual revenues match its authorised revenues to recover its operating costs plus a reasonable return on investment. In the U.S. context there are numerous examples of currently successful mechanisms that regulators and governing boards can use as models (Midgen-Ostrander et al., 2014; Sullivan et al., 2011). Also, decoupling requires staff to take only ministerial action to perform a simple true-up comparison of actual revenues to the allowed revenues and adjusting tariffs to return or recover any over- or under-collection the following period (Sullivan et al., 2011).

In terms of sectors, decoupling is applicable to both electricity and natural gas utilities. While both sectors share similar cost structures that are dominated by high fixed costs, they face different underlying trends in terms of customer revenues. The gas sector tends to face declining average revenues per customer over time, leading to revenue and profit erosion between tariff proceedings in traditional tariff making. In turn, the electricity sector anticipates increasing average revenues per customer that would result in increasing profits in traditional tariff making. For these reasons, gas utilities have tended to be more open to implementing decoupling mechanisms than have electric utilities (NARUC, 2007). However, in response to longer-term expectation about expenses and environmental costs, a small but growing number of electric utilities in the U.S. have either implemented, requested, or are investigating decoupling (see also Figure 1).

Concerning applicability to the EU context, decoupling mechanisms (in the European context generally referred to as revenue-cap regulation) are in fact already to a large extent applied to the regulation of electricity network operators. The legal basis for this is essentially provided by Article 15.4 of the Energy Efficiency Directive (EED) (2012/27/EU) and its recent amendment (2018/2002) which requires Member States to introduce regulatory policies similar to decoupling for transmission system operators and distribution system operators in the electricity sector. In addition, Article 18.8 of the new Electricity Market Regulation (2019/943) strengthens the role of performance-based network regulation for DSOs. Accordingly, the majority of EU Member States have decoupling (revenue cap) mechanisms in place for the regulation of DSOs in the electricity sector, including Germany, France, Great Britain and Spain (Pató et al., 2019).

However, no equivalent legal provision exists for natural gas TSOs and DSOs in the EU (Bayer, 2015). A practical point of intervention could be the Natural Gas Directive (2009/73/EC). In Article 40 (d), the Directive lists, among others, other objectives of Member States' regulatory bodies as "helping to achieve, in the most cost-effective way, the development of secure, reliable and efficient non-discriminatory systems that are consumer oriented, and promoting system adequacy and, in line with general energy policy objectives, energy efficiency as well as the integration of large and small scale production of gas from renewable energy sources and distributed production in both transmission and distribution networks." Adding further provisions could help strengthen the standing of decoupling/revenue cap regulation in the natural gas sector – given that, at present, at least four Member States still have traditional cost plus-based regulation in place for gas TSOs and DSOs while only 15 Member States have adopted decoupling mechanisms (CEER, 2020).

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ABOUT ENEFIRST

ENEFIRST is a 3-year project funded under the Horizon2020 programme, which gathers a consortium of partners from across sectors and regions: IEECP, BPIE, Fraunhofer ISI, CEU, RAP, IREES, TU Wien.

From definition to implementation, ENEFIRST aims at making the "Efficiency First" (E1st) principle more concrete and operational, better understand its relevance for decision processes related to energy demand and supply, its broader impacts across sectors and markets, focusing on the building sector and related energy systems in EU Member States.

> ***E1st gives priority to demand-side resources whenever they are more cost-effective from a societal perspective than investments in energy infrastructure in meeting policy objectives. It is a decision principle that is applied systematically at any level to energy-related investment planning and enabled by an "equal opportunity" policy design.***

ENEFIRST combines policy analysis and quantitative assessments of E1st impacts to develop policy guidelines and recommendations, following a process with continuous exchanges with stakeholders.

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