2 Understanding energy sector terminology used in this report

The energy sector is rife with confusing acronyms and esoteric concepts. To assist in reading this report, we review some relevant terms here. A list of acronyms appeared on page 10.

2.1 Energy sector basics

To begin understanding the energy sector, it is important to focus on two aspects (as illustrated in Figure 11). First, what is the ***value chain*** for the relevant fuel or technology? The term value chain refers to the full life cycle of a product as it moves from production to transport to final consumption. Second, which aspects of that value chain are ***competitive***, meaning prices are set by market forces, and which aspects are ***regulated***, with prices set according to procedures established by regulatory bodies. While all value chain segments are regulated from the perspective of health, safety, environmental impact, and consumer protection, only some have prices subject to regulatory approval. Figure 12 provides an illustration of the electricity supply value chain, differentiating between aspects of the value chain that are subject to an exclusive franchise with those that could be competitive.

Figure 11. Essential aspects for understanding the energy sector

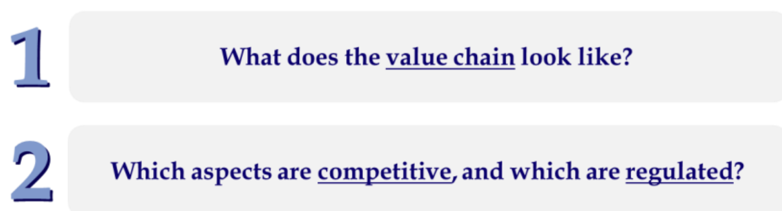
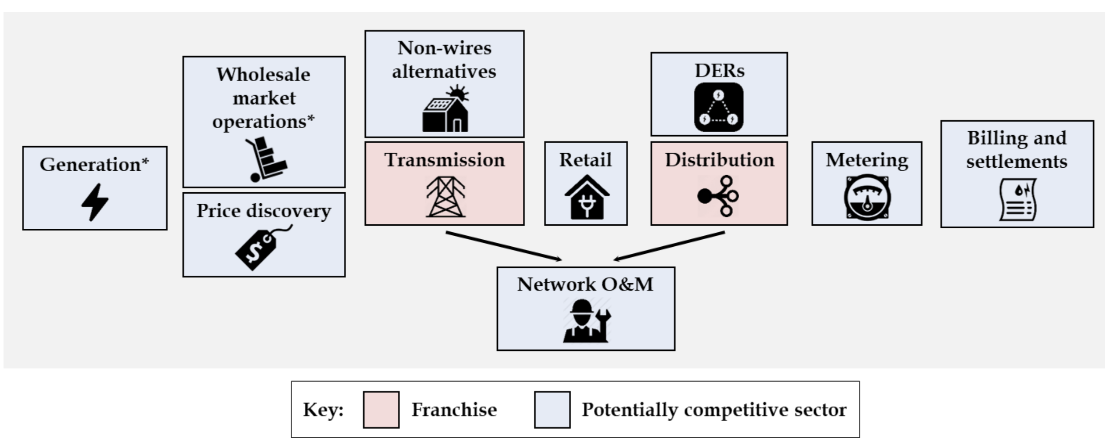


Figure 12. The electricity supply value chain



* Independent system operator ("ISO") may be deployed.

Note: DERs – distributed energy resources; O&M – operation and maintenance.

Hoosiers consume energy in a variety of ways. In some cases (gasoline, for example) they purchase the fuel directly and convert it in a vehicle or device. In others, such as electricity, the primary fuel is converted prior to delivery. Prices for coal are also market-based, and because coal moves by modes of transportation that compete with one another (rail, truck, and barge), transport costs are also market-based. Prices for oil, natural gas, and refined products are largely unregulated; however, rates on the pipelines through which they move are regulated, meaning their final price to the consumer incorporates both the base commodity price, set by market forces, and the delivery cost, set by regulators. In some states, electricity markets have been deregulated, meaning a similar paradigm applies – market forces set the base price of electricity, but the cost of transmitting it over high voltage transmission lines and lower voltage distribution lines is regulated.

2.2 Market participants

Entities that provide often essential services as near monopolies at regulated rates are referred to as ***utilities***. Interstate oil and natural gas pipelines and transmission lines are regulated at the Federal level by the US Federal Energy Regulatory Commission ("FERC"). The North American Electric Reliability Corporation ("NERC") sets mandatory reliability standards and is overseen by FERC. ***Investor-owned*** local natural gas and electricity distribution utilities are owned by shareholders and regulated by state commissions; in Indiana, this role belongs to the Indiana Utility Regulatory Commission ("IURC"). Some utilities have different ownership structures; a ***municipal utility*** ("muni") is owned by a city or town, and sometimes regulated only by the relevant local authority; a ***co-operative utility*** ("co-op") is owned by its members and usually regulated only by its board. Coal mines, oil and natural gas producers, and generators that are not owned by utilities (sometimes referred to as ***independent power producers*** ("IPPs")) are not utilities, and are free to set their own rates.

Indiana's utilities build generation to meet their projected load based on ***Integrated Resource Plans*** ("IRPs"), which must be filed with the IURC every three years. IRPs are intended to force utilities to consider a range of technologies and resources to meet future needs; these resources can include conservation and demand response, based on the theory that if it costs less to encourage beneficial changes to demand than it does to build a new power plant to meet that demand, the utility should consider energy efficiency programs in lieu of new construction.

In addition to using generation from facilities that they own, Indiana utilities also purchase power from IPPs and the wholesale market. In some states, utilities only transmit power, and customers can arrange for their own supplies through competitive retailers who participate in wholesale markets on their behalf. Wholesale electricity markets in the US Midwest and Northeast are organized around ***Independent System Operators*** ("ISOs").[8] Two ISOs serve Indiana, the Midcontinent ISO ("MISO") (highlighted in orange in Figure 13), and the PJM Interconnection ("PJM") (highlighted in yellow). ISOs coordinate flows on the transmission lines in their region, identify transmission investment needs, and also run markets for a set of products (energy, capacity, ancillary services ("A/S"), and transmission congestion rights). Utilities retain ownership of the transmission lines and the responsibility for physically maintaining them; the

[8] Some ISOs are also referred to as ***Regional Transmission Organizations*** ("RTOs").

ISO's role is to make sure that the capacity on those transmission lines is allocated fairly to facilitate competition among generators.

NERC, ISOs, the IURC, and utilities all have a role with regards to maintaining system reliability. NERC sets technical standards for reliability and monitors utility performance; ISOs manage and plan the transmission system consistent with NERC standards, and utilities justify future generation and distribution system investments to the IURC as being needed to meet NERC standards.

While ISOs differ in how they define the products that they optimize, generally, ***energy*** refers to the production from a generator (or amount of load reduction made available) that is transmitted to consumers for instantaneous use. ***Capacity*** can be thought of as a sort of reservation payment, intended to assure that sufficient generation and load reduction is available to meet maximum expected requirements; given the need for a reserve margin, there will inevitably be some resources which run infrequently, yet need to be maintained. Some portion of reserve capacity needs to be held ready to run, but not yet providing energy, to assure that when demand fluctuates, increases in load can be immediately met. This portion of reserve capacity that is standing ready to run immediately receives ***ancillary services*** payments for the period when it is not providing energy. A plant or demand reduction resource can receive payments for all three services. ISOs also facilitate markets in hedges against ***transmission congestion***; those that purchase the hedges can avoid additional charges during periods when transmission lines are fully loaded. Figure 13 presents a map of US ISOs and Figure 14 lists Indiana utilities participating in MISO and PJM.

Figure 13. Map of US ISOs

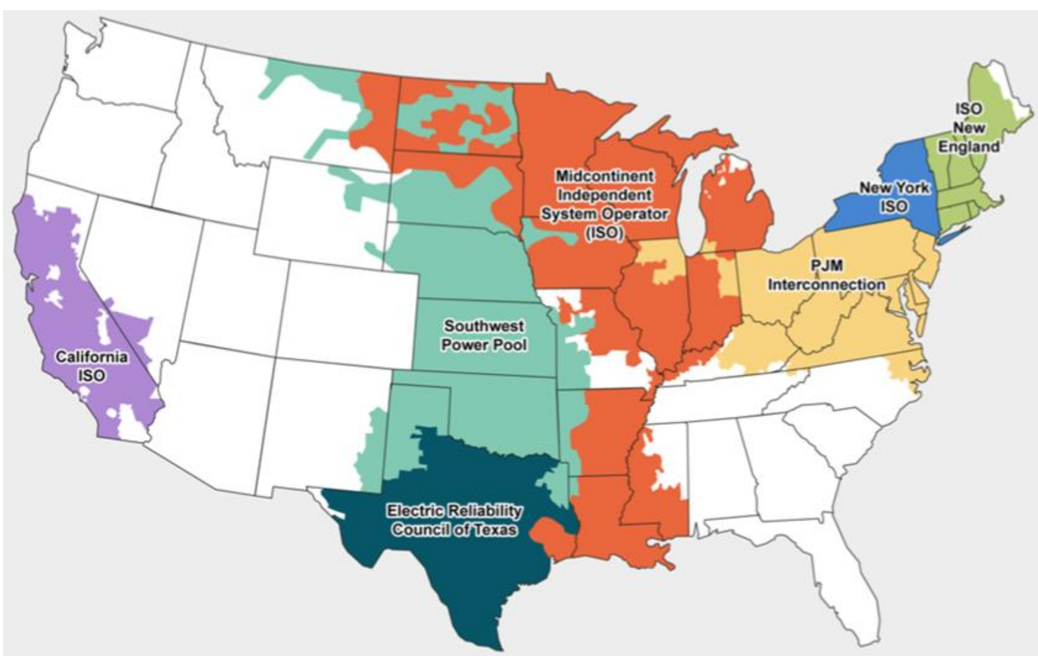


Figure 14. Indiana utilities participating in MISO and PJM

Characteristics	MISO	PJM
Participating Indiana utilities	Duke, NIPSCO, IPL, Vectren, AEP, Hoosier Energy, IMPA, and WVPA	AEP *(including its Indiana subsidiary I&M)*, IMPA, and WVPA
Transmission lines (across footprint)	71,800 miles	84,236 miles
Generation capacity (across footprint)	175,528 MW	180,086 MW
Annual billings	$29.9 billion	$49.8 billion
Headquarters	Carmel, Indiana	Audubon, Pennsylvania

Sources: Indiana Office of Utility Consumer Counselor ("OUCC"), MISO Corporate Information, and PJM website.

2.3 Rate design

Utility regulation is often said to rest upon a ***regulatory compact***, in which utilities are granted exclusive franchises and an ***obligation to serve*** in exchange for being allowed to charge ***just and reasonable*** rates. Just and reasonable has been interpreted in North America to mean rates which provide an investor the opportunity to achieve a return consistent with that which could be received in an unregulated industry facing a similar level of risk, provided service expectations are met. Returns are not guaranteed, however. Rates are also expected to be ***non-discriminatory***, in that groups of customers with similar characteristics are treated in the same way.[9]

Electric utilities in Indiana are ***vertically integrated***; this means that they own assets across the value chain, including generation, transmission, and distribution. The basis for setting rates is what is known as ***cost of service*** (see Section 6.3 for an overview of the rate setting process under a cost of service regime). Simplistically, a utility adds up all of its costs (the total of which is referred to as its ***revenue requirement***) and allocates them across its customers, who are sometimes referred to as ***ratepayers***. Costs include capital costs associated with the construction of generating stations, transformers, wires, poles, and associated infrastructure (collectively, the ***rate base***), divided by the number of years of expected service; operating costs, which are largely related to the cost of employees; and the cost of capital, which is the return on ratebase and compensates lenders and shareholders of the utility. Some costs are charges on a per unit (usually a kilowatt-hour ("kWh")) basis, meaning customers only pay based on what they use; some are charged based on peak demand (per kilowatt, or "kW") other costs are charged on a per customer basis, meaning a portion of the customer's bill is not impacted by usage. Rates may be based on forecast or historical costs; in either case, a true up to actual costs may be necessary periodically.

A key principle of rate design is ***cost causation***, meaning that the rates that customers pay should reflect the costs that their usage imposes on the system. Because devices that store electricity have historically been expensive (though the technology is improving in this regard), the entire system (generating stations and transmission and distribution facilities) needs to be built so as to instantaneously meet potential peak demand, plus a reserve margin in case portions of the system

[9] FERC. *An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities.* June 2018.

are unavailable at peak times. Based on cost causation, customers that contribute disproportionately to peak load are charged higher rates than those that do not. Utilities often segment their customers into industrial, commercial, and residential load, and charge different rates to each. Residential customers often pay the highest rate because they consume a higher proportion of their load at peak times. By contrast, industrial rates are often lowest because many industrial customers consume at a more or less steady level throughout the day, and some may not be connected at a distribution voltage, thus using less of the system.

While cost of service is the foundation for rate-setting across North America, some jurisdictions have been experimenting with ways to incorporate better incentives for utilities into rates. The implementation of ***performance-based ratemaking*** ("PBR"), coupled with specific service quality standards, is seen in some jurisdictions as a way to encourage efficiency while guiding utilities to focus on areas of greatest priority to policymakers. Under PBR, utilities that meet efficiency or other objectives are allowed to earn a bit more than the target cost of capital, while ratepayers benefit from rates that may increase more slowly due to the associated efficiency gains. As discussed in Section 6.2, Indiana's rate design includes some incentive properties, but does not fully incorporate PBR.

2.4 Other important concepts

When wholesale power becomes available more cheaply than resources built under ratebase, assets are sometimes referred to as "stranded." ***Stranded assets*** are often long-lived assets built many years ago which are less efficient than current resources, or use a more costly fuel. In some cases, utilities can provide benefits to ratepayers by not running plants that they own, and substituting their output with purchases on the wholesale market. However, in the meantime, the utilities need to recover the remaining cost of the asset that is no longer being used. In such circumstances, in some states, regulators have allowed the utilities to retire the stranded asset while stretching out the recovery period for the remaining cost so that existing customers are not as burdened by the repayment.

Many states have enacted policies to encourage renewable or zero-emitting resources. Often the basis for these policies is a ***renewables portfolio standard*** ("RPS"). The RPS requires utilities, or in cases that allow them, retailers, to procure a specified percentage of their load from a set of qualifying resources. Qualifying resources vary from state to state, but normally include wind, solar, hydro, and biomass, though the definitions within these categories may also differ. Utilities and retailers often are allowed to demonstrate that they have met the RPS requirement by purchasing the necessary amount of ***renewable energy certificates*** ("RECs"). Qualifying resources receive RECs for each megawatt hour ("MWh") that they produce; they are then able to sell these RECs to utilities and retailers that need them to meet their RPS requirements.

Declining technology costs, Federal incentives, and smaller unit sizes have contributed to the proliferation of ***distributed energy resources*** ("DERs"). DERs are generally small scale, and often renewable, resources connected at a distribution voltage or situated behind the meter ("BTM"). The term can encompass storage and dispatchable load as well. Some commentators see the potential for DERs to reconfigure the electricity supply network, resulting in two-way flows on the distribution system and reducing the need for larger, centralized generating stations. DERs can also be used as non-wires alternatives ("NWAs") to defer capex in the distribution or transmission system. However, DERs pose challenges to utilities and ISOs, as they may not be able to forecast or control production from these resources. This poses challenges for coordination, planning, and optimization.