

Electricity Networks: Infrastructure and Operations

Too complex for a resource?

Dennis Volk

INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 28 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

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Foreword

At the October 2011 Governing Board Meeting at Ministerial Level, IEA (International Energy Agency) member countries endorsed the IEA Electricity Security Action Plan (ESAP). The proposed electricity security work program reflects the multiple challenges of keeping electricity systems secure and affordable while also seeking to rapidly reduce carbon dioxide (CO₂) emissions. In particular, the large-scale deployment of renewables needed to meet decarbonisation policy targets will lead to more volatile power flows, which will create new challenges and require real-time responses.

Well designed and integrated policies, regulations, institutions and system frameworks will be needed to operate and develop electricity systems efficiently in order to deliver, and maintain, least-cost electricity systems. Quite clearly, governments and regulators will play a crucial role in competitive decision making.

The ESAP consists of five work streams that support the implementation of frameworks for:

1. **Generation Operation and Investment.** This examines the operational and investment challenges facing electricity generation in the context of decarbonisation.
2. **Network Operation and Investment.** This examines the operational and investment challenges affecting electricity transmission and distribution networks as they respond to the new and more dynamic real-time demands created by continuing liberalisation and large-scale deployment of variable renewable generation. It draws from, and complements, the other work streams where appropriate.
3. **Regional Electricity Market Integration.** This identifies and examines the important issues affecting electricity market integration, including policy/legal, regulatory, system operation/security, spot/financial market and upstream fuel market dimensions. It draws from the other work streams as appropriate, and from regional market development experience in member countries.
4. **Demand Response.** This examines the main issues and challenges associated with increasing demand response, reflecting its considerable potential to improve electricity sector efficiency, flexibility and reliability.
5. **Emergency Preparedness.** This develops a framework for integrating electricity security assessment into IEA peer review programs – Emergency Response Reviews and In-depth Reviews – to improve knowledge and information sharing on electricity security matters among IEA member countries, with a view to helping strengthen power system security and emergency preparedness.

“Too complex for a resource?” is an issue paper on electricity transmission and distribution network operations and investment in liberalised electricity markets with low carbon policies. It presents the complex policy, regulatory and market context in which networks have to provide services to the market. It considers ways of strengthening the networks’ role in the overall power system to reduce the public good characteristics and permit market participants to decide whether, to what extent and when, to use it as a resource. This publication is part of a series on electricity published in conjunction with the overall Electricity Security Action Plan (ESAP).

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Executive summary

This report analyses how electricity market liberalisation and increasing shares of variable renewable generation can affect electricity network performance. It raises high-level policy issues with implications for network operations and investments. This has been prepared as part of the IEA work programme to help implement the *Electricity Security Action Plan* endorsed at the 2011 IEA Ministerial.¹

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The electricity system cannot function without its distribution and transmission networks and the services they provide. Today and over the long term, the way these networks operate and develop will determine the cost-efficiency and reliability of overall electricity systems as they continue to decarbonise. Hence the importance of electricity networks in the overall electricity system. Policies to promote market liberalisation and to introduce economic regulation of networks have fundamentally changed the way we use network services; more dynamic and regional power flows have emerged while increasingly effective regulatory arrangements have increased the use of network capacity. These results have created new hurdles for maintaining reliability,² and also raise new investment challenges. These challenges are now magnified by the large-scale introduction of variable renewable generation, on both the transmission aspect and at the distribution level.

An integrated policy and regulatory approach will be needed to ensure that we meet the networks' operational, investment and related regulatory challenges in a fashion that enables efficient operation and timely development of the networks to support, guide and meet liberalisation and decarbonisation goals. An effective policy approach should seek to maintain the power generation sectors' competitiveness, facilitate efficient market development and the timely and well-located, least-cost deployment of renewables.

In recent years, some IEA electricity regions have seen a further push towards more market-based frameworks for network operations and development. This progress aims to transform often less transparent and centrally-administered network services into service markets for least-cost and technology-neutral system development. However, improvements in regulatory frameworks can still be made in most electricity regions across the globe. More individual decision making of all relevant market players with regard to network service use is essential and will have to be based upon price signals for various system services. Certainly the uptake of such market-based solutions has often benefited, and will continue to benefit, from convinced political

¹ Reports have been prepared to date include: "Securing Power during the Transition – Generation Investment and Operation Issues in Electricity Markets with Low-Carbon Policies" (IEA, 2012d) and "Empowering Customer Choice in Electricity Markets" (IEA, 2011b).

² Reliability in this context encompasses the ability of the electricity networks as part of the power system's value chain to deliver electricity to all connected users within acceptable standards and in the amounts desired. Reliability possesses two key dimensions: adequacy and security, which for example have been defined by the North American Electric Reliability Council (NERC) and the International Council on Large Electric Systems (CIGRE).

Adequacy refers to the power system's ability to supply the aggregate electric power and energy requirements of the customers within component ratings and voltage limits, taking into account planned and reasonably expected unplanned outages of system components.

Security refers to the ability of a power system to withstand sudden disturbances such as electric short circuits or unanticipated losses of system components or unusual load conditions together with operating constraints. In this sense, security refers to the operational reliability of an existing power system. This security dimension can also have several facets. For instance, security can refer to the resilience of electricity systems to various forms of external threat, such as cyber or physical attack. It also incorporates the notion of system integrity, which refers to the preservation of interconnected system operation, or the avoidance of uncontrolled separation, in the presence of severe disturbances.

This publication will focus on the key issues associated with strengthening the reliability dimension of transmission and distribution system security in competitive electricity markets.

decision makers, highly skilled regulators and system operators as well as from improved modern IT (information technology) technologies capabilities.

This report discusses the main factors that drive network-related trends in greater detail and the significant policy and regulatory issues that need to be considered in this context. In the future, outdated network services may fail to maintain desired reliability levels, support least-cost electricity systems and maximise the efficient use of renewable resources. Transforming network services from a public good into a resource is a powerful way to ensure that network services are perceived as essential, valuable, and thus also partially complementary, services within the electricity system. This can change the way individual market participants demand and use the various network services, contribute to solve the “flexibility question” and the “missing money problem”, reduce electricity market price distortions and also avoid or minimise heavy handed regulations and market interventions during “the transition”.

Management capabilities and frameworks for distribution and transmission operators

Real-time situational awareness and power flow management is needed to manage the dynamic power flows that result from liberalisation and the large-scale deployment of variable renewable generation. This management has to be effectively co-ordinated: on a horizontal basis, among regional power systems that span multiple transmission system operators; and on a vertical basis among each regional transmission system operator and its underlying distribution operator. New regulations and technologies are needed to transform passive distribution networks into actively managed operational network zones.

Liberalisation has opened up formerly closed regions for competitive electricity supply. This development has often increased the number of manageable generators across an electricity region. This development has brought new power flows from different locations often on an inter-regional bases. Network operators are now required to deal with and co-ordinate an increasing number of generators and associated power flows. Technologies often have to be introduced to create real time awareness of these flows and to enhance their management capabilities for maintaining system reliability. Aside from market liberalisation, the integration of renewables requires increased efforts for reliable electricity system management. Variable renewables such as wind and solar photovoltaic (PV) bring more volatile power flows with changing weather conditions, which are also prone to forecast errors. In addition, the average transport distances of electricity flows are likely to increase as renewable generators are often located more remotely from demand.

Horizontal coordination across interconnected regions is of growing significance to ensure reliability, efficiency and promote decarbonisation among regional power systems that span multiple jurisdictions. Considerable progress has been made through the deployment of “smart grid” technologies, with better information sharing and improved operational practices. However, opportunities remain to strengthen inter-regional coordination with regard to operational practices. Inter-regional practices should include improved information sharing, wider-area situational awareness, aligned operational protocols and procedures, as well as improved forecasting methodologies, in particular for variable renewables.

Further, the rapid development of distributed generation, and variable renewables in particular, increasingly requires changes to the way distribution networks are operated. In the past, and in the majority of cases still, distribution networks were passive loads, managed and supplied from the overlying transmission level. The uptake of distributed variable renewable generation has now changed the nature of the power flows at the distribution level. This raises system security

challenges similar to those experienced at the transmission level. However, most distribution system operators do not have the capability to accurately monitor performance in real-time or to intervene where needed to maintain reliable system operations. This fundamental change in distribution network use raises a range of legal, regulatory and operational questions for policy makers. Assessing the specific requirements of future operational management procedures for distribution networks is one of the major challenges to a reliable and efficient integration of renewables at the distribution level.

Finally, managing the vertical interface for system operations between distribution and transmission networks can become a significant issue with more dynamic electricity flows. Distributed generation can lead to reverse power flows into the transmission grid. An enhanced interface supporting more co-ordinated operations across the vertical interface can help strengthen reliability and resilience, while supporting higher levels of renewables integration and better economic outcomes. Again, significant policy, regulatory and operational development will be needed to help address these challenges.

More efficient operations can ensure effective use of existing network infrastructures. Any market and regulatory framework that encourages more efficient operations and use should be implemented consistently on a system-wide basis that reflects relative costs for network operations, network assets and generation. The balance should aim to minimise costs among the entire electricity system.

A consequence of dynamic and regional power flows is the changing nature of network capacity utilisation. These consequences are likely to be experienced on the distribution and transmission level. Network bottlenecks already appear on the transmission level and, with increasing volumes of distributed generation, can also be expected on the distribution level. However, prior to each network infrastructure upgrade, maximising the use of existing network capacities can be the more economic solution. This will require network operators to undertake close to real-time assessments of available network capacities and power flows and to be able to adjust network capability accordingly. Frameworks for economic regulation must account for the need to improve system operation management capabilities over time. Regulations that focus on minimising network costs can show suboptimal results for the integration of markets and renewables. Regulatory frameworks therefore need to establish incentives for network operators and network planners that achieve a right balance between operational costs, network asset costs and electricity supply costs. This balance should aim at minimising system-wide costs throughout the whole electricity value chain.

Distribution and transmission infrastructure development

The integration of power flows and variable renewables can affect network investment requirements on the distribution and transmission level. To facilitate the timely development of a least-cost electricity system, efficient regulatory investment planning frameworks, incentives and structures are required. Integrated planning frameworks are emerging at the transmission level but need to be further developed. Similarly, more holistic planning and development processes need to be developed urgently at distribution level to allow for an efficient and timely distribution network development with an efficient transmission/distribution interface.

More dynamic power flows resulting from liberalisation and decarbonisation policies are likely to be reflected in new points of congestion or increased chronic congestion. This may be especially difficult to overcome at the distribution level where this kind of congestion appears for the first time. Part of the solution may involve new network infrastructure investments. However,

planning and regulatory arrangements may not be sufficient for the new challenges. A loss of coordination with unbundling may serve to exacerbate these problems in some circumstances. The investment-planning framework, and the nature and scope of regulated investment incentives, are crucial to facilitating timely and efficient investments. The regulatory framework should aim at system-wide cost minimisation that reflects the competitive interplay between network asset costs, network operational costs, electricity supply costs and other solutions such as demand response. The planning framework should be open to all kinds of technological solutions and aim to incentivise all relevant market players so as to identify least-cost system-wide solutions for each situation. This deviates from classical network planning frameworks with centralised and technology-specific solution determination. A focus on system-wide costs throughout the whole value chain is required to avoid delayed or even hindered network investments. Regulations that focus solely on minimising network costs can fail to account for the resulting system-wide benefits across the electricity system. In principle, incentive-based regulatory frameworks can foster independent planning behaviour and facilitate least-cost solutions for new investments. So far the theoretical benefits of such regulatory frameworks remain to be fully achieved, as most new significant network investments are treated outside these frameworks. This gives rise to the application of cost-benefit assessments covering the quantifiable implications throughout the whole electricity value chain. Such assessments are required during the investment development phase as well as during regulatory cost control.

Whilst planning frameworks continue to evolve and develop for transmission, comparable frameworks remain under-developed at distribution levels. The implementation of such frameworks can help to maximise reliability and efficiency, while enhancing the potential to increase renewables integration. The vertical coordination of investment planning between distribution and transmission networks is becoming increasingly important where growing volumes of distributed renewable generation are transforming the way distribution systems are used. A more efficient planning interface is needed to help find least-cost investment solutions across related transmission and distribution systems to facilitate reliable and efficient electricity flows. Addressing these challenges raises a range of related legal, regulatory and investment coordination policy issues.

Planning and investment approval processes must be objective, transparent and provide sufficient scrutiny to ensure that the most efficient and cost-effective combination of generation, network and demand response solutions are adopted to meet evolving patterns of use. Physical network capacity upgrades should compete with potential alternative solutions, including demand response, electricity storage, distributed generation, distribution-level network investments and smarter network management technologies. Whilst the investment costs from those non-network investments have to be recovered through participation in markets from other parts of the electricity value chain, an open planning framework should allow for these investments to compete on an equal basis to help identify least-cost technology and system-wide solutions. Independent network planners could play an important role in facilitating information exchange and the development of a level playing field between competing alternatives.

The application of efficient planning frameworks should also be extended to the integration of renewables. Cost-benefit assessments need to specifically address net incremental benefits and costs associated with the deployment of renewables. Further, the proportional and accurate allocation of network costs and benefits between beneficiaries can strengthen incentives to help determining least-cost system-wide developments.

Decarbonisation is the main benefit of integrating renewables into electricity systems. However, the full cost of externalities associated with carbon emissions is not currently reflected in existing carbon pricing regimes and there are no carbon pricing regimes. This lack of sufficient pricing can result in under-investment in low carbon generation and related network infrastructure. To

compensate, governments have adopted support schemes based more on deterministic obligations than quantifiable benefit-cost analysis of net public benefit. In the absence of quantifiable benefits and beneficiaries, the resulting network costs are often socialised among various network users. Even with quantifiable benefits available from integrating conventional generators, cost socialisation is frequently applied. However, network infrastructure is not free and can form a significant part of a power systems' investment need. This is especially the case in regional markets with longer distance power flows where more expensive network technologies, such as high voltage direct current (HVDC) cables, are sometimes used to connect remote renewable generation facilities. In the absence of accurate cost allocation generators will locate facilities to maximise individual revenues regardless of the full integration costs. These actions can lead to imbalances between network asset costs, operational network costs and generation costs and thus can increase system-wide costs above cost-effective levels. A more efficient allocation of network costs can establish stronger incentives on all parties to help minimise the system-wide costs of renewable integration. Opportunities to improve cost allocation schemes should be further examined.

More efficient, transparent and accountable approaches to network development including the application of system-wide planning, total cost accounting and fair cost allocation can reduce network costs while improving acceptance of new network investments. More open and consultative planning processes can further enhance public acceptance towards new transmission and distribution lines.

Electricity networks that are developed on a more holistic basis reflecting system-wide planning and more objective cost-benefit analyses can enable more efficient, timely and cost-effective investments. Improved efficiency and transparency can help to build general acceptance towards new network investments and will also help foster local acceptance. Transparent and consultative network infrastructure planning processes can build local community understanding and allow proponents to draw on specific local knowledge to support appropriate power system developments. An effective two-way communication and development process between proponents and the local community can help to reduce potential local resistance to necessary network investments. Benefit-cost analysis needs to take account of all applicable costs to the greatest extent possible, including the environmental and distribution costs to local communities. Unaccounted costs can become a significant driver for local resistance during the siting process.

Appropriate and transparent allocation of costs to beneficiaries can also help to build wider community acceptance and if non-beneficiaries are required to shoulder a deal of the investment costs, this can lead to challenged acceptance.

Bodies responsible for investment approvals need to adopt transparent procedures and deliver objective decisions that accommodate the various interests of all relevant stakeholders throughout the whole development and siting process. All relevant decisions should be made publicly available and include explanations of the rational underpinning those decisions.

Applying enhanced market-based solutions for increased system-wide efficiency, reliability and integration of renewables

As natural monopolies, network services and related system operations are subject to regulation and a high degree of centralised management. However, well-functioning markets can liberate the market and improve reliability and network performance, especially during peak periods or when network services are scarce. This can lead to a more efficient existing network infrastructure use and the reducing incremental network investment costs, operational costs and electricity supply costs. They can also provide locational signals for

efficient and well-located, market-based generation investments that reflect network costs. In some markets some of these complementary market-based incentives have already been applied at the transmission level.

The introduction of more market-based solutions is generally reliant on price signals to create incentives for timely and efficient responses. This includes prices for system services, which are transparent, accurate, reliable and undistorted with the ability to reflect changing system conditions and demands over time. It also requires market participants to be exposed to price changes in a manner that will encourage an efficient and timely response. However, market-based approaches are not a complete substitute for efficient, centralised system operation. The influence of centralised approaches can be reduced but will still be needed to ensure reliable and secure operation of power systems, reflecting the unique properties of electricity services. Regulatory responses will also be needed to maintain reliable system operation and sufficient network services reflecting the public good characteristics of network services and reserve adequacy for secure system operations. However, as power systems develop the introduction of more market-based services can reduce or sometimes avoid heavy-handed regulatory responses.

For example, effective congestion management frameworks already exist at the transmission level and have been applied in some markets to help reduce the need for centralised intervention. These frameworks could be more fully applied to help increase the contribution of market participants to help solve local congestion issues at least cost. The introduction of hedging instruments for market participants can support the effectiveness of such congestion management frameworks and can support in identifying the market value of congestion. Applying the causer-pays principle with regard to incremental network costs can help to guide generators' decisions where to locate. Their efficient application can help to make best use of the existing infrastructure and to minimise electricity system costs at the interplay between network assets, network operations and electricity supply costs.

Assessing applied operational procedures against best practices or academic evidence can help further improving effective procedures for operational management on the transmission level, which are now becoming increasingly important for efficiently integrating renewable generators. In theory the operational procedures as well as technological requirements and options for enhancing operators' management capabilities are well understood on the transmission level. This is based upon the fact that transmission levels needed to be handled transparently and efficiently to ensure the desired high level of competition from electricity market liberalisation of the last decade(s). In practice this has led to widespread academic advice and improved regulatory frameworks for the application of fair and reliable system operations on the transmission level. Nevertheless, even on the transmission level, there can often still be opportunities for improving currently applied operational procedures.

Consideration of how to mobilise market-based responses to help improve network management and performance at the distribution level is only beginning. The application of "smart" metering and "smart" grid technologies is a significant step to improving distribution system reliability and performance, including demand response, while minimising incremental investment requirements. As generation shares from variable renewable generators increase, improved awareness and management capabilities of these power flows will be required for maintaining reliability and more effective system integration. The more efficient incorporation of renewable generation into market-based approaches on the distribution and transmission level can bring further benefits.

Reliable and more efficient system operation is directly influenced by the growing integration of variable renewables. As the shares of variable generation grow in power systems, their system-wide influence is growing. The incorporation of renewable generation into more market-based

approaches therefore can help to maintain high levels of reliability while it can also increase the efficiency of network service provision. For example, the existing frameworks for balancing services were often designed for serving the needs of loads and dispatchable generators, whose supply and demand patterns were largely predictable on the day-ahead time scale. Variable renewables have a substantial supply forecast error in day-ahead markets, which can add considerably to balancing requirements and costs unless closer to real-time balancing markets are introduced. Further efficiencies can be achieved by the introduction of competitive prices for imbalances and more rigorous application of causer-pays principles to imbalances combined with more market-based approaches to the procurement of balancing services. Exposing all generators, including variable renewable generators, to balancing costs can encourage more efficient self-management and reduce the needs for centralised renewable generation curtailment and also negative price events on the electricity market. The development of such competitive balancing frameworks with higher levels of self-management is still at an early stage of development but has the potential to support more reliable and cost efficient system-wide decarbonisation. Such balancing of service markets can also contribute to avoiding the introduction of capacity payments for solving conventional generators' missing money problems as balancing service provision results in larger markets for these generators. Such markets, if co-ordinated with the electricity market can further attract the right resources to provide with the flexibility required in the future to back up variable renewable generation.

The uptake of distributed variable renewable generation now increasingly changes the nature of the power flows at the distribution level. This requires changes in the way distribution networks are operated and developed for maintaining reliability. Assessing the specific requirements of future procedures for distribution networks is one of the major challenges to be resolved to permit reliable and efficient integration of renewables at the distribution level. Such procedures can potentially also benefit from introducing more market-based solutions to activate the multiple market participants on the supply and demand side of the distribution level. In an environment of efficient retail market designs new business models can eventually evolve, which aggregate small-scale market participants from the demand and supply-side to virtual power plants.

Introduction

Modern economies are critically dependent on reliable and affordable electricity supplies to maintain and foster economic growth and social welfare. In the past, electricity systems have been planned and operated by vertically integrated utilities with main their focus on maintaining reliable regional supply, mostly with large scale and dispatchable generators. These arrangements have benefitted from holistic system planning, economies of scale, investment certainty and reliable power flows, but have also suffered from monopolistic supply structures, with reduced levels of innovation, lower service quality and a lack of price and customer competition.

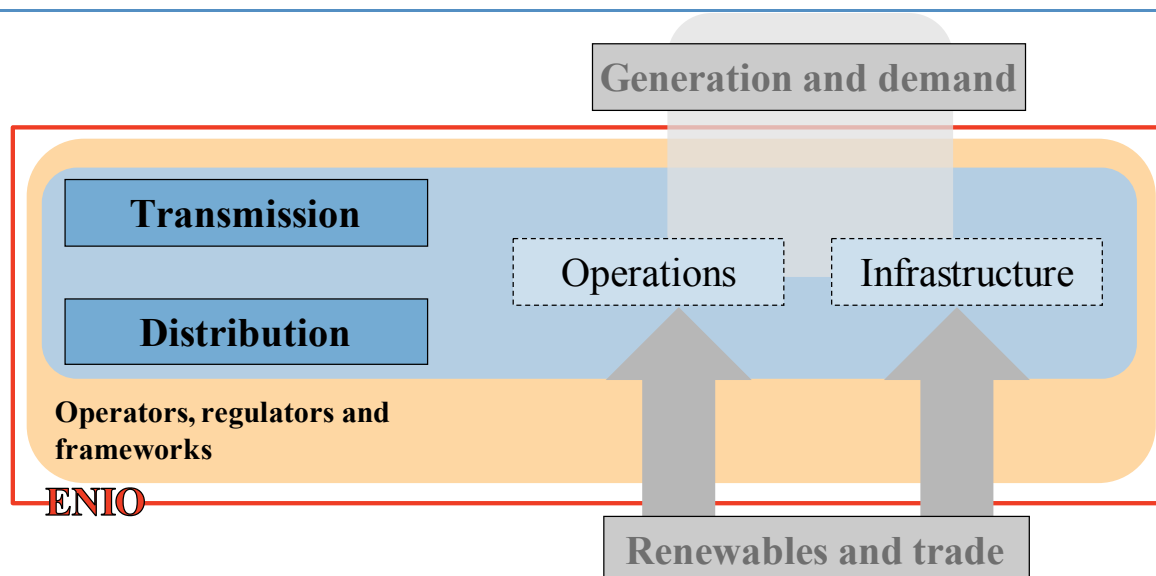
The liberalisation of many electricity regions across IEA member countries has changed these former arrangements, splitting up the integrated utilities into separate network business and other, empowering customers, enhancing private and competitive operations and investments as well as increasing transparency. Under these arrangements electricity markets have served customers from IEA member countries well for sometimes almost two decades. During the same time research, policy focus and regulations improved the way electricity networks are operated and developed to serve competitive electricity markets.

Independent of market rules, the underlying physics cause a high level of interdependencies across the system and within single parts. Their existence provides for a significant level of substitutability across (single) parts of the system, which often offers several solutions to one “problem”. This opens up opportunities for least-cost solutions finding across the systems. Unlike in the competitive generation sector electricity network performance is a result of regulatory choices and frameworks. It is the role of efficient regulatory frameworks to establish a cost optimum between the operational services and asset services of networks whilst also supporting least-cost systems, comprising of network and electricity service costs. For instance, a network operators’ aim to reduce costs for the provision of local network services can generally be reached by obliging generators via technical connection requirements. But it is questionable whether the added costs on the supply side would be lower than other service supply measures coming directly from the network. These examples indicate the scope and potential effects of interdependencies across the electricity sector, which makes electricity networks significant enablers for an efficiently functioning electricity market with competitive prices. These interdependencies and the resulting changes on a system-wide base should be accounted for when imposing framework changes.

The role electricity networks play in electricity markets is still evolving and shows multiple variations across IEA member countries. The aim remains to establish networks as a resource within the electricity market, which market participants can chose to use at their own expense. This development continues to change the thinking that network services are (almost) free public goods for (most) market participants.

While this development proceeds, the decarbonisation and integration of large shares of variable renewable generators and trade flows as well as generator relocation come with additional demands to the network services. The need for decarbonisation can drive the renewable sources’ share to a level of 21% in global energy supply by 2035. In electricity sectors, this share can exceeds 40% in Europe, almost 40% in other OECD economies and more than 20% in the United States (IEA, 2012a). Country- or region-specific targets often exceed these levels of least-cost carbon abatement. Electricity networks infrastructure and operations (ENIO) have economic implications (Figure 1).

Figure 1 • Aspects covered under ENIO and interrelated parts of the system



Note: Unless otherwise indicated, all material in figures and tables derives from IEA data and analysis.

In light of the above, the following section of this report discusses transmission networks with regard to integrating more dynamic power flows and larger shares of (variable) renewables. The focus is on important network services, operational aspects and efficient infrastructure investments, and the way policies and regulations (can) evolve to incentivise efficient behaviour of all market participants whilst using these services. Services are identified where the possible active participation of, and cost allocation to, responsible parties, including variable renewable generators, can be beneficial or even necessary for highest system reliability, economics and decarbonisation.

The third section of the report highlights distribution networks, their biggest challenges and solutions. The deployment of significant shares of renewables and progress with empowered customers will take place in the distribution network and will transform today's passive load centres into active supply and demand centres. In this regard, the paper discusses the requirements of sharpening distribution network operations, planning and the interface with transmission networks.

In the fourth section, network operators' and regulators' important tasks, institutional structures and available regulatory tools are briefly mentioned. The paper concludes with high-level recommendations derived from the report and further research requirements on transmission and distribution levels within, or outside, the ESAP to further improve electricity markets.

Transmission networks: turning a public good into a resource

Even under the current regulatory frameworks electricity networks can operate reliably with the continuous integration of increasing power flows and variable renewables. This holds true as long as network operators can technically manage power flows and generators in real time. However, these real-time awareness and management capabilities are only just emerging and their implementation should continue. Further, the mode of operating, restructuring and expanding transmission networks so that they serve competitive electricity markets and thereby integrate renewables and support trade flows, will be a lengthy process. Though the current regulatory frameworks for the provision of network services³ have to date delivered sufficient flexibility, reliability as well as economic efficiency in the electricity sector, electricity system fundamentals are changing significantly with decarbonisation, continuing market liberalisation and regional market integration. These changes can exceed the current network service capabilities, which are likely to result in more expensive and less efficient decarbonisation, market liberalisation and regional market integration.⁴ Therefore the adaptation of the existing regulatory frameworks to improve network service provision seems to become more and more important. Due to both the interrelated nature of network services and competitive part of the electricity market, any framework change must be developed in view of the system-wide consequences. Only holistic policy and regulatory adaptation strategies and frameworks will likely deliver reliable and least-cost electricity systems. Further, due to the amount and complexity of necessary system changes, the suitability of administrative network service provision existing with high levels of regulatory decision making will be questionable. It is likely that more efficient, market-based solutions will become the norm as they encourage individual market participants' decision making for delivering desirable policy outcomes (Pollitt, 2013). The introduction of more market-based approaches in network services' provision will significantly reduce the public good character of network services. This transforms electricity network services into usable resources for market participants, which they can then assess against other solutions. But, more market-based solutions can be disadvantageous in that increasing transaction costs or shifts in market power can result and the benefits, costs, risks and regional specifications will have to be assessed prior to rule changes taking effect.

Key findings • Changing power systems can herald the introduction of more market-based network services, so transforming network services into resources. These services can become more efficient, compared to the more heavy-handed regulatory market interventions and command and control approaches, for guiding the transition.

Decarbonisation and liberalisation will affect important network services, including network congestion management, system balancing, system reliability, system real-time awareness and management capabilities and network infrastructure. The following part of this section describes important transmission network related aspects with regard to power flow and renewables integration and their predominant framework in which networks are embedded. The section continues with the impact on electricity systems and identifies potential solutions and holistic planning frameworks to be included to incentivise co-ordinated and least-cost behaviour across the entire electricity system. The section concludes with the public acceptance challenge of new

³ Network services can be largely grouped into infrastructure services and operational services. Infrastructure services relate to sufficient network assets to make power flows happen and operational services comprise a set of services such as balancing services, reactive power provision, congestion management or the provision of losses to maintain electricity systems reliable. Operational services are often also called ancillary services.

⁴ The report focuses on decarbonisation and continuing liberalization while aspects around regional electricity market integration are discussed in another workstream under the ESAP.

transmission network investments, a factor that must often be overcome for the efficient integration of power flows and renewables. Once the public acceptance challenge can be managed, the risk of underinvestment into required new network infrastructure can be avoided. This discussion sheds light on the emergence of holistic planning and siting frameworks for solving this very significant aspect and avoiding potential underinvestment.

Transmission network operations: time to catch up

In general, network operations can be regarded as system services aiming at maintaining network reliability whilst supporting the competitive electricity markets. Network operations, often called ancillary services, avoid infrastructure overloading or supply imbalances that would otherwise lead to technical failures, blackouts or damages to generators, loads or the network. As electricity systems were often established under regional-specific administration, it is impossible to refer to one definition of global network operations. With regard to the papers' purpose on maintaining reliable systems operation under the influence of increasing power flows and renewable generation, the focus is on three important ancillary operational services that are prone to changes:⁵

- electricity flow scheduling and system congestion control;
- reactive power supply for load flow and voltage control;
- balancing reserve operations.

To date, these services often resisted the process of electricity market liberalisation and therefore remain a public good service type. For the services, the central service operators often determine each service's level of demand to maintain system reliability. Owing to past experiences, the service supply is sometimes provided by third parties, but mostly by conventional generators. A consequence of such engineered and administered service provision is often cost socialisation, as responsibilities shift away from market participants thereby causing the network service needs to shift towards system operators. The negative effects of administered service provisions and cost socialisation often relate to economic inefficiencies. These inefficiencies can result from inefficient behavioural incentives to market participants as they have no exposure to, or responsibility for, their costs. Such approaches may not reduce individual service demands to the level where system-wide costs are minimised. Further, administered services often lack transparency and open access and thus can hinder the introduction of more competitive solutions. Therefore, administered services are more prone to support monopolistic market structures, which will require more regulatory scrutiny and can further raise information asymmetry and subsequent inaccurate regulatory decision making.

While network operations designed as engineered services have served electricity markets reliably well before and during the first decade of liberalisation, increasing trade flows and variable renewables integration will increase the demand for these services. Further, as electricity systems are no longer planned in an integrated way by a vertically-integrated company, system reliability challenges are likely to occur more often. Depending on the applied operational service design, reliability-based interventions by system operators can become more frequent and distortive to decisions from the electricity market.

A more frequent use of reliability interventions through an engineered service can also contribute to conventional generators' missing money problem, which has often led to the

⁵ Black start capabilities and the provision of network losses are two other significant services completing the ancillary services of network operators.

introduction of capacity payments as, for example, discussed in widespread academic literature and ESAP's generation work stream (IEA, 2012d).

Key findings • The demand for essential system services will rise with growing shares of renewables and trade flows. In cases where services are centrally administered, reliability-based interventions by central operators and regulators may also increase. More market-based approaches still have to be implemented as they can yield various economic benefits and halt conventional generators' missing money problems.

These administered and central processes have their advantages in their comparably lower transaction costs for all market participants. In addition, the central approach ensures coordinated measures in a complex and interactive system with numerous market participants. This central coordination itself is helpful as it sometimes can aggregate demand levels for system services. As service demand levels from various stakeholders can go in opposite directions, central coordination can net out these single demand bids and only supply the lower aggregated residual. On the other hand, administered services can face the increasing disadvantages of missing incentives to responsible market participants and economic inefficiency. With the addressed integration changes other disadvantages can appear within electricity systems, such as the perceived or real discrimination of certain market participants and growing pressure on regulators. Regulators will more often have to decide upon the right set of technical measures and operational procedures and these decisions will often have to be taken under pressing time frames and with a natural shortage of information (information asymmetry). To mitigate existing, and avoid potential additional, disadvantages, implementing more market-based solutions for the provision of the system services mentioned above is beneficial. This implementation is likely to come with added transaction and management costs as services become more sophisticated. In addition, services should be designed in a way that the beneficial effect of netting out service demands through central coordination remains. Ex ante cost-benefit assessments can therefore help identify the right measure for each electricity region show situations where incremental costs will be overcompensated by reduced inefficiencies.

In general, more market-based solutions should include six principles:

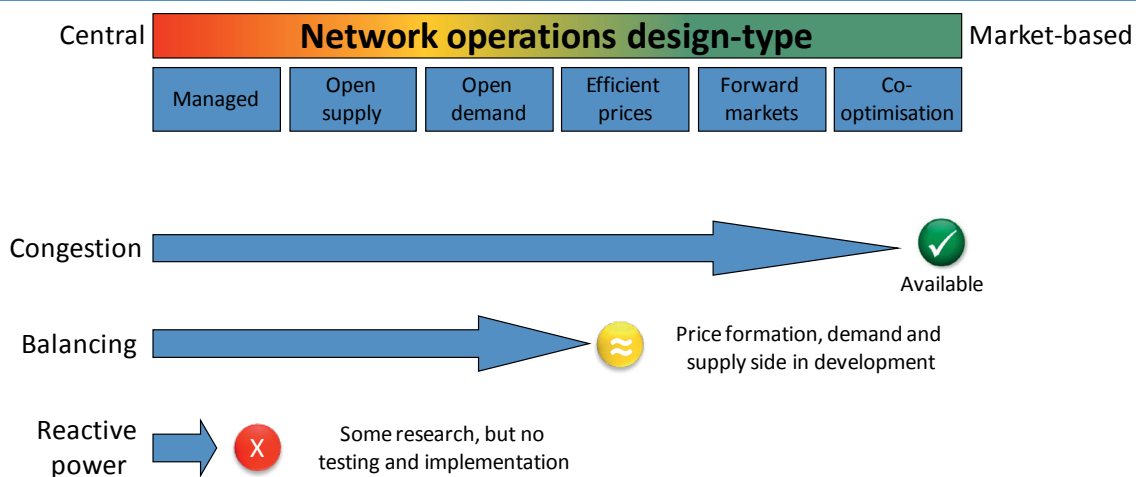
- efficient and undistorted price formation;
- clear product definition;
- fair cost allocation;
- openness and transparency;
- forward looking;
- local accuracy.

Efficiently designed services are needed with close to real-time undistorted prices for immediate reactions to electricity market changes. Allocating the costs to the responsible parties additionally places responsibilities in their rightful place. This also avoids blurred incentives to single market participants by cost socialisation. This will require market participants' awareness of the demands they put on network services and increased responsibility for paying for these services. It is often still the case that generators are not exposed to the costs they are responsible for. In some cases conventional generators already face these costs but only in very rare cases is this cost allocation, via active market participation, applied to renewable generators. To reap the benefits of all generators' active network service participation, the network service provision should be designed openly and transparently so as to allow and encourage participation of the various existing and potential service supply sources. In addition, service products have to be accurately defined and delineated from other services to efficiently attract suitable service providers. Introducing accurate locational information can often foster accurate service demand

and provision as they take into account physical network realities, which can demand local solutions or are limited by locational constraints. A long-term horizon and ability to risk-hedge the provision and demand for operational services can further contribute to efficient, competitive and risk-balanced network services. These long-term approaches can also avoid unexpected system changes to all market participants, which can otherwise threaten system reliability, and so enhance the demand for short-term and over-expensive countermeasures undertaken by system operators.

The addressed changes from the integration of renewables and power flows are already in full swing in some countries and regions and envisaged in several others. In addition, changing the regulatory frameworks and the underlying operational procedures will often take time. It can thus be beneficial to start the assessment and desired transition from engineered approaches to more market-based solutions in a timely manner whilst the electricity system is still running to a large extent on existing assets. Timely changes could address the operational challenges at their sources as well as also foster efficient decision making for long-lasting and capital-intensive investments. Market-based solutions are either available (congestion management) or in development (balancing markets) in two of the three relevant cases (Figure 2). Progress in the implementation of efficient markets for reactive power management remains poor, probably as a result of the generally lower significance in terms of system costs and their technical complexity. Further research and testing is required for the latter services prior to implementation, whereas the implementation of congestion management regimes only remains subject to cost-benefit assessments.

Figure 2 • Efficient market instruments and status quo of network operations

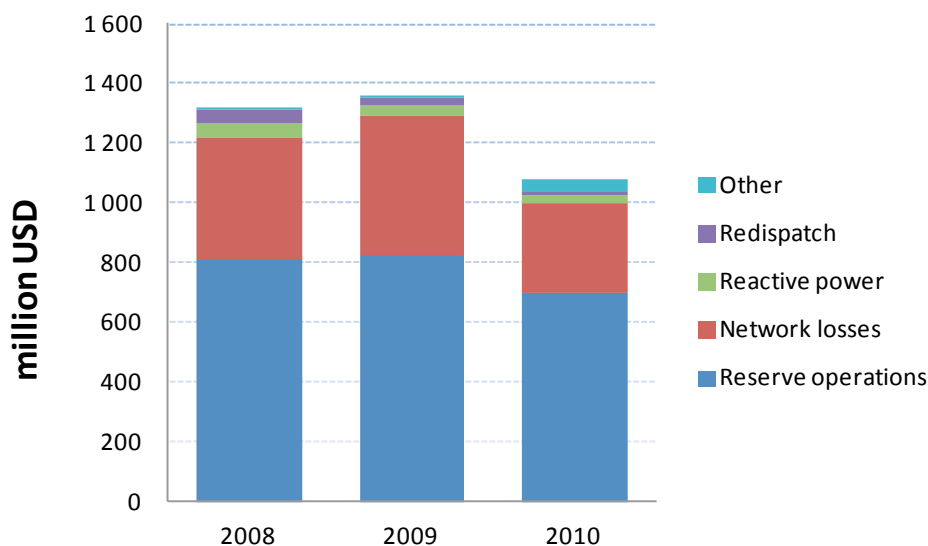


Key findings • Efficiently designed service markets can offer non-discriminatory self-management of the growing number of market participants as well as reliability and cost efficiency. Costs for system services should be allocated commensurate to the individual cost-responsibilities, including renewable generators. Region-specific assessments are often required prior to the implementation of market-based solutions and should also take into account the timeframe for implementation.

The share of operational costs on total costs for transmission networks varies by region and network technical specifications. The same cost variation also often applies for the disaggregation of shares within the operational costs. Additionally these costs can vary over time with changing patterns of investments, system tasks or system design changes. In most OECD countries, however, the network operators' reserve costs seem to represent the highest operational cost factor, followed by costs for compensating network losses, costs for reactive

power provision and dispatch management. Cost disaggregation is exemplary for Germany's four transmission system operators (Figure 3). In 2009, the net operational costs⁶ represented 65% of the total network costs⁷ and were largely dominated by costs for reserve operations (61%) and network losses (34%).⁸ Whilst this demonstrates a grasp of the current economic relevance, these costs do not always express all these services' system-wide importance. A shortfall in the provision of re-dispatch or reactive power will inevitably cause system damages or blackouts with significant costs to society.

Figure 3 • Operational net costs in Germany's transmission electricity networks⁹



Source: data from BNetzA, 2010; BNetzA, 2011a.

Flow dispatch and handling of scarce network capacities: dealing with congestion

Before market liberalisation electricity systems were centrally designed and operated under stable conditions where an integrated network and generation planner added bulky generators and transmission lines. Liberalisation and unbundling has reduced the internal optimisation process between conventional generator location and network developments and has made existing network congestion visible for the first time. In addition, renewable generators also often choose favourable locations¹⁰ for their independent benefit maximisation. However, these geographic locations can show a lack of sufficient transmission capacity for reaching demand centres, leading to network congestion. Additionally, market liberalisation results in new electricity flows and the existing transmission networks have to accommodate these new routes of electricity flows.

⁶ total costs minus revenues for the management.

⁷ including capital costs for new investments, maintenance and depreciation.

⁸ Since there is less influence of renewable generators to the level of network losses, network losses will be outside the scope of operational procedures.

⁹ Converted from EUR to USD with an exchange rate of 1:1.26. It has to be noted that the drop of operational costs between 2009 and 2010 represents a one-off effect caused by integrating the formerly four markets for reserve operations into one market.

¹⁰ windy or sunny regions.

Box 1 • Scheduling, system control and dispatch service

Generators compete for the provision of electricity during a certain time frame in a market-based process and their bids (amount, time and price) get aggregated in an ascending order reflecting their bid price (merit-order principle). A market operator matches these bids with the expected demand and schedules the generators' prior to the physical delivery time. Network operators will check on the expected merit-order based schedules and assess the resulting power flows through the network. This assessment is required for reliability reasons as power flows can influence the voltage levels and can also lead to unreliable congestion levels arising on transmission lines between network nodes. Operators also take into account the effects to power flows on transmission lines, caused by failures of significant infrastructure parts such as transmission lines or power plants (n-1 principle).¹¹

Congestion levels can be reached by thermal limits of transmission lines where the electric current heats the conductors up to a temperature above which either the conductor material would start to soften or, due to line-sag, the clearance to ground would drop beyond its required minimum. The maximum allowed continuous conductor temperature, which is relevant for these limits, can differ largely between network operators with values reaching from 50 °C to 100 °C (CONSENTEC, 2001). An individual line's temperature limit depends on several factors, such as material and age, line geometry and imposed security standards. Environmental conditions such as ambient temperature, wind speed and solar radiation have a significant effect on conductor cooling and therefore on the real-time thermal-limitations. Operators often chose conservative "worst case" situations with regard to these environmental conditions and through that define the maximal allowed electric current.

Congestion management can be described as preventing electricity flows, which would otherwise continuously or frequently lead to exceeding thermal limits and threaten system reliability, from happening. As thermal limits are line-specific and depend upon environmental conditions the network operator has to have locational knowledge upon each expected power flow through all lines of the transmission system, the available transmission system capacities and the expected environmental conditions. As power flows and environmental conditions can vary over time and quite frequently it is inevitable to continuously perform system reliability assessments with continuously updated power flows and environmental conditions. In case of exceeding reliability limits network operators intervene into the scheduled bids from the competitive electricity market prior to their physical execution in dispatching down relevant generators. In the absence of demand response operators will then dispatch-up other available generation capacity to fulfil the remaining supply task. Operators can select to-be re-dispatched generators for fulfilling the supply task with more market-based approaches, using marginal price bids comparable to those on the electricity market. Nevertheless, even this more market-based approach represents a level of missing information for generators as they are less aware of re-dispatch time, location and price finding.

Liberalised electricity systems on their path towards decarbonisation are likely to face rising congestion levels. Congestion is already visible in several US regions such as California, Seattle and Portland (US DOE, 2009b) and also in Europe, where, for example, the German transmission network faces congestion in several regions. To maintain a reliable transmission network during times of high usage and congestion, operators have to intervene into the free market-based scheduling process of supply and demand by curtailment¹² and congestion management. Congestion management can be described as preventing electricity flows to happen which would otherwise threaten system reliability levels.¹³ Extra market supply costs accompany reliability-

¹¹ To ensure stable network operations planning for system faults play a major role. In that regard the n-1 principle has been established and is commonly adapted by network planners. This n-1 principle is applied to prevent for emergencies with cascading impacts, defined as the uncontrolled loss of a sequence of additional network elements caused by an initial contingency, resulting from the incident of one system component such as a generator, a transmission line or a transformer.

¹² Curtailment is the reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of reaching the limits of system reliability.

¹³ Thermal limits are the key aspect for capping electricity flows on lines if they exceed certain limits.

based congestion management as more expensive generators, which are not located “behind a congestion”, will replace initially scheduled cheaper generators.

Arising congestion problem levels are also one of the drivers for current plans to upgrade existing and build new transmission infrastructures. From a total electricity system perspective however it can be more economical to accept some levels of congestion rather than to fully upgrade the network infrastructure. This trade off between networks and congestion will be further discussed in the planning section, whereas the following discussion spans around efficient operational congestion management as opposed to network upgrades or during the time networks develop. In addition to highest operational efficiency, an efficiently designed congestion management can further support the determination of the economic value of alleviated transportation bottlenecks at all times and for all network users. Using market-based evaluation methodologies can support network planners and regulators in their assessment of taking long-term mitigation measures.

Key findings • Liberalisation, emerging power flows and new flow patterns from renewable generators reveal weak spots in the existing infrastructure and can increase congestion levels. Congestion management is required to ensure system reliability but comes at the price of costly market interventions. Nevertheless, it is not always economical to alleviate all levels of congestion.

Whilst reliability is the primary task of congestion management, market-based approaches that accurately reflect local conditions can show beneficial outcomes in terms of system operation economics. Even though a transmission network generally appears as covering a large geographical area, its technical demands can be rather local as line-specifications and flow conditions differ locally. With the ongoing integration of locally dispersed generation, the demand for local system state information and local system- and congestion-management will arise.

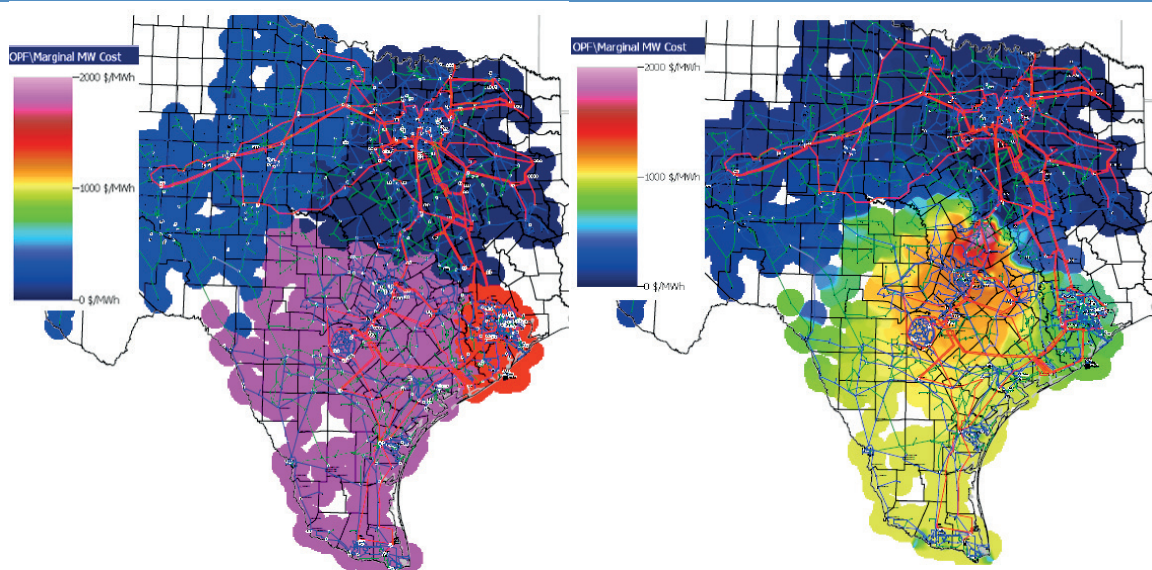
Three main types of congestion management designs exist and the important questions arising from choosing the correct type for any system relate to the extent of self-management, cost efficiency and information accuracy. How accurately should the costs of congestion management be allocated to those network users causing the congestion? How accurate will information have to be in order to facilitate efficient market behaviour even beyond the operational management of congestion? What are the expected benefits of more accurate, and sophisticated, management approaches and what are the associated negative effects and additional costs?

Economic literature as well as cost-benefit assessments often suggest that the most accurate and beneficial management-type for network congestion is locational marginal pricing (LMP), often also referred to as nodal pricing (Schweppe *et al.*, 1988). Here the network operator becomes more of an information provider for market participants, signalling the costs for certain network services that the various electricity flows cause at specific locations and paths. Such solutions trigger market participants' self-management and reduce administered measures that lack individual generators' self-management incentives. Currently, the application of LMP in OECD countries can be found in New Zealand and several US markets, such as the California Independent System Operator (CAISO), PJM Interconnection Regional Transmission Organization (PJM), New York Independent System Operator (NYISO), Midwest Independent System Operator (MISO), Independent System Operator New England (ISO-NE) or the Electric Reliability Council of Texas (ERCOT). All of these markets are operated by Independent System Operators (ISOs) and some of these are already on their way to reaching larger shares of variable renewables. In CAISO, 20.6% of 2011 retail sales were met with renewable power with the aim to increase this share to 33% by 2020. In 2011, ERCOT's wind generation share of total production was close to 9% and is expected to increase in wind generation capacity from over 10 gigawatt (GW) in 2011 to 18 GW (ERCOT, 2012 and Public Utilities Commission of Texas (PUCT), 2013).

A cost-benefit assessment prior to significant market management changes in the western US electricity systems identified the implementation of LMP as responsible for roughly 50% of all benefits arising from restructuring (TCA, 2006) whilst other benefits were achieved by additional system management improvements as well as further improved dynamic efficiencies which resulted from co-ordinated infrastructure planning. On the other hand, this approach requires more transparent, reliable and comprehensive data handling to all market participants, which generally increases the transaction costs. In addition, risks have to be handled accordingly, such as the risk of price spikes based upon temporary network scarcity. Another risk can be the effects on market power in more localised markets. All these benefits and risks vary by region so making specific cost-benefit assessments indispensable. Depending on the system and the expected developments, the long-run benefits of nodal approaches can outweigh the annual operational benefits.

Basically, LMP is derived from the day-ahead schedules of the electricity market where system operators perform localized supply/demand assessments on each node, as well as resulting power flow assessments on each transmission line between the nodes (see Annex A for a further technical description). This enables the determination of nodal prices, which represent the full marginal costs, consisting of the price for electricity production and network use, of supplying an additional megawatt hour (MWh) at a certain node, either by generation at each node or by imports from other nodes.

Figure 4 • Pricing contours in ERCOT zonal (left) and nodal (right) market conditions during congestion



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: PE, 2008.

Each localised power flow uses transmission network capacity and causes system losses, and the localisation enables precise determination and allocation of these costs to those power flows and entities responsible for these costs. This implies that generators will receive the specific marginal nodal price and loads and pay the specific marginal nodal price. Benefit gains from such accurate cost allocation will arise from reduced network losses. Benefits also arise from a precise full-

cost¹⁴ determination and allocation at each node, which limits price effects of congestion to affected regions, an effect that is lost in a less accurate zonal or uniform pricing approach where a wider area with the high prices of marginal generation is covered. In the same vein, ERCOT calculated potential savings on two congested areas of USD 175 million in 2008, which would have arisen through a more precise cost determination during one year (PE, 2008). A locational price difference exists in the ERCOT market without (left) and with (right) marginal locational prices (Figure 4). While the zonal marginal price leads to marginal prices being paid by larger regions and underlying customers, locational marginal prices limit these high marginal prices to a much smaller affected region.

Other research comparing the economic effects from nodal, zonal or uniform approaches endorses these findings. (Green, 2007) estimated welfare benefits¹⁵ for the UK electricity market of 1.3% annually by moving from uniform to nodal pricing and also found a lower vulnerability to market power. This initially counter-intuitive argument of reduced market power vulnerability can be applicable to generator owners with larger generation portfolios in particular, as nodal prices contain market power to localised conditions. This reduces the effectiveness of market power abuse for a larger remaining generator fleet. Additionally, this effect depends largely on local conditions and cannot be generalised, making an upfront assessment necessary.

The two other congestion management approaches show lower geographical accuracy in terms of congestion pricing, which can undermine the economic efficiencies described above. Zonal pricing can be understood as nodal pricing but with lower local resolution. In this regard, the costs of congestion and system losses are not associated to specific lines but rather to specific zones and the accuracy will depend on the zonal design. Advantages of this less sophisticated approach are lower requirements for market participants to deal with potentially vast local price varieties. Additionally a zonal approach also reduces the effects of price volatility present in nodal approaches and reduces single market participants' exposure to costs. Compared to a nodal approach this reduces the need for introducing sophisticated transmission rights. But this approach is disadvantageous owing to the blurred operational and investment incentives for market participants. Determining the price zones can be a further challenge for regulators who are influenced by several market participants. Within a nodal approach the price differences are based on fundamentals, which also ensure "automatic" price adjustment when required. Several interest groups can also become influence the adjustment of zonal prices.

From the implementation and operation perspective, uniform pricing is the least-cost management approach. However, it is also the least accurate management form that averages out all costs of network use and congestion amongst network users. Compared to nodal pricing, a zonal or uniform pricing approach thus represents less sophisticated congestion management measures with a maximum degree of operational network cost socialisation. This cost socialisation can undermine the efficient operational behaviour of all market participants, including renewable generators. It can further increase the need for centralized and inefficient market interventions to resolve congestion and also blur possible long-run investment signals, which could create additional inefficiencies in the long run.

Key findings • Local recognition is required for system operators to maintain system reliability and localised congestion pricing can be used to foster best economic behaviour and maximise the use of existing network capacity. Practical implementation has successfully started in some regions and countries while other, less accurate approaches can fall short of achieving their economic benefits.

¹⁴ generation and network use.

¹⁵ with regards to generators' revenues.

Whilst nodal approaches contain congestion costs to the relevant lines, this cost focus can create high price events during times of capacity scarcity and increase price risks for network users exposed to these costs. This effect can become exaggerated with the integration of variable renewables and power flows as their resulting power flow changes happen more often and also on different nodes. Risk-hedging instruments can be introduced in the form of transmission rights and the introduction of these rights as tradable products¹⁶ allow for maximised capacity use in theory (Hogan, W., 1990 and Kristiansen, T., 2004) and praxis (FERC, 2002).

Operators will allocate transmission rights to network users and auction-based allocation processes can achieve high economic benefits as they reveal the value of transmission capacity for all market participants. With large renewable generation shares, it will become increasingly important for these generators to participate fully in an undistorted allocation process as to avoid a shrinking market coverage. For the moment, renewable generation enjoys free and firm priority access rights and associated costs of network service use are often socialised. Efficient allocation of transmission rights can further help; identifying to-be-curtailed power sources in times of scarcity and the allocation of revenues also contribute to the refinancing of operational network costs. Tradable (financial) transmission rights reveal the value of transmission for each generator at each time and give valuable information in times of network scarcity. As opportunity costs vary among generators so the value for transmitting electricity varies over time. Allowing for secondary trade between generators reveals the generator-specific value to the market and can lead to the efficient use of transmission capacity. In financial transmission rights maximise network usage by providing for short-term flexibility and disincentivising owners from artificially withholding rights. Efficient capacity utilisation will become increasingly important with the integration of variable renewables where network utilisation patterns between different generators will change more frequently (ISO/RTO Council, 2009).

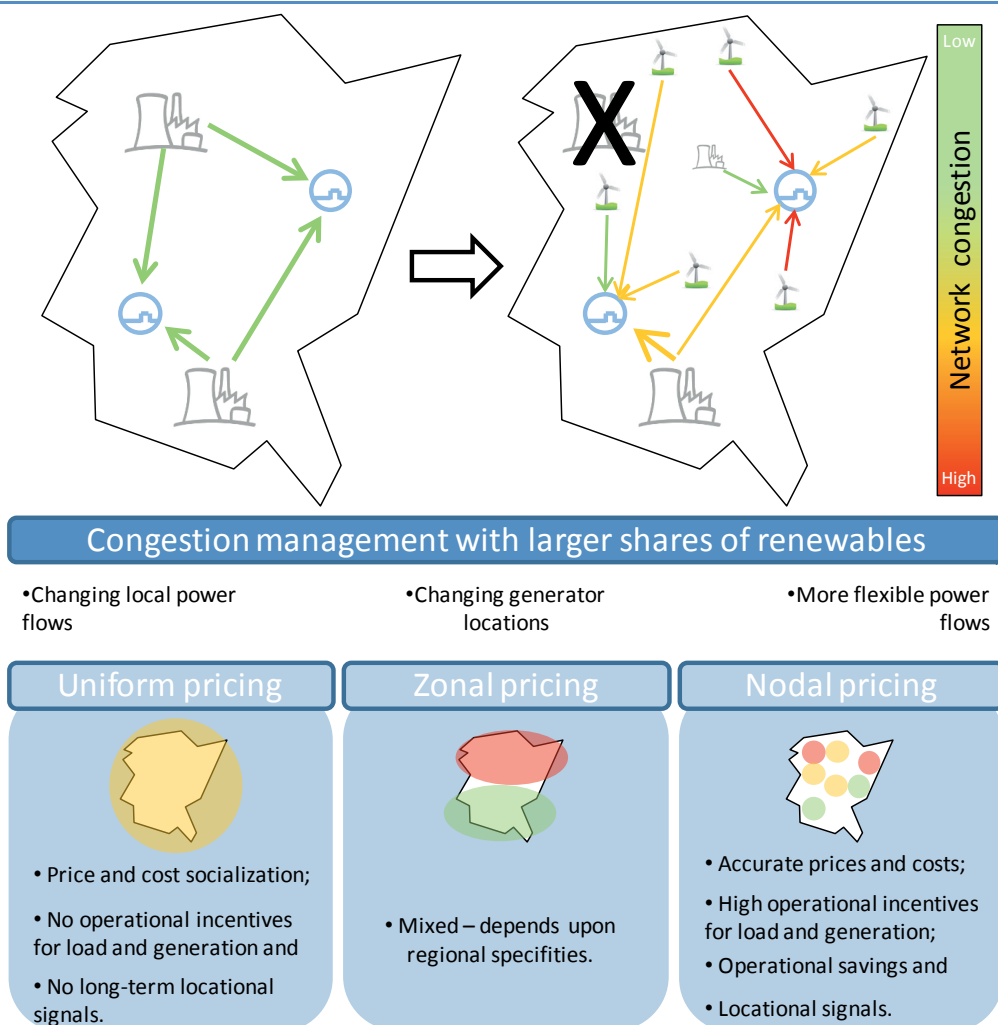
Continuously increasing power flows from variable renewables will further demand the formation of LMP and handling of transmission rights closer to real-time. This development is driven by the increasing forecast errors of variable renewables, particularly the introduction (as discussed below) of the nodal day-ahead or hour-ahead schedules. Close to real-time congestion market settlement can enhance the accuracy of network system state assessments, which are required for reliable and efficient network operations and can compensate for the inefficiencies resulting from higher forecast errors. One example of close-to-real-time co-optimised market operations (electricity and congestion) can be found in PJM, where the system operator (SO) uses an hourly intraday nodal congestion settlement (PJM, 2012b) and a five-minute system state evaluation to cope with short-term deviations. With increasingly fluctuating shares of variable renewables it might even become beneficial to bring the settlement process even closer to real time.

Accuracy, upfront clarity and fair cost allocation result from this management approach. As individual market participants directly factor in these costs into their market-based bidding behaviour, significant operational cost savings are possible through efficiently managed congestion levels and reduced network losses. Applied LMP further reduces the need for inefficient cost socialisation of network services, which often also comes with acceptance issues and lower levels of support from locally- and regionally-affected market participants. As a result, LMP with tradable transmission rights can be regarded as a natural extension of the classical electricity wholesale market theory and practice. Transparency associated with nodal design is likely to become increasingly beneficial in markets with large shares of variable renewable generation and power flows. Here transparency allows for an open view on the system constraints that are limiting the dispatch of all types of generators. With the integration of trade

¹⁶ Tradable rights as opposed to firm rights are known as Financial Transmission Rights.

flows and renewables management of network congestion may be in more frequent demand (Figure 5).

Figure 5 • Congestion management options and benefits with growing shares of renewables



The more efficient the service design, the more efficient the network service costs can be. However, it is likely that the network service efficiency will become reduced with the way renewables currently enter electricity systems via priority dispatch. Priority dispatch for renewable generators¹⁷ is a powerful tool for ensuring a high level of renewables integration. At the same time priority dispatch also leaves out the opportunity to identify the generators and related electricity flows, which deliver the highest system value during network scarcity at all times. This value can be quite generator- and time-specific and represent the generators' opportunity costs¹⁸ – basically their changing willingness to pay for the use of congested lines. This enables individual generators to choose when, and at what price, they can continue (or stop)

¹⁷ Priority dispatch for renewable generators provides these generators with priority access to the market and the network. Independent of their short-run marginal costs and their competitiveness against other sources, renewable generators will be the first generation source dispatched to supply the market. In cases where one or more of the various types of network services become scarce, threatening to exceed system reliability thresholds, the expected power flows will have to be re-arranged by system operators. This re-dispatch is a divergence from the pure market-based dispatch decisions of suppliers. Priority dispatch to renewable generators ensures that re-dispatch considers renewable generation curtailment only as a last resort after all other measures have failed, as long as reliable operations can be maintained.

¹⁸ Opportunity costs can be influenced by individual generators' contract obligations for electricity supply and/or network service provision and additional supply opportunities, which would be foregone in cases of congestion.

using the network services supports least-cost electricity supply and this should include renewable generators. Accurate prices for network use play an important role to support all generators' choices and these prices should also be imposed to renewable generators as their shares on the network become significant. Other means to maintain reliability during congestion is the administered curtailment of some generators, including renewables. However, this is likely to reduce market efficiency as it fails to inform market participants about the costs of using network services and generators have little incentive to avoid or resolve congestion. Network service pricing with sufficient local recognition can also support all generators' decisions on where to locate as network congestion and costs of network use can be factored into the revenue calculations.

Key findings • Auctioning, trading and risk hedging transmission rights under the inclusion of renewable generation will maximise capacity use and economic efficiency gains. Closer to real-time allocation and trading of transmission rights will be required to compensate growing forecast errors with renewable feed-in. In general, all generators, including renewables, should be exposed to accurate network pricing to support system-efficiency.

Next to the direct economic benefits of nodal congestion management, the use of accurate system information can be beneficial for the provision of balancing services and reactive power supply in the short- and long-run. Operators start to use local system knowledge for establishing markets for the more efficient provision of balancing services and reactive power. Additionally, combining the local value of network use with the assessment of potential new infrastructure investments is already under way and supports investment planning on the network level (PJM, 2012d). Those values can further be used to identify and foster a least-cost balance between incremental network and generation costs in the long run, where generators factor in the long-run network costs into their decisions regarding location. Guiding locational decisions will be particularly relevant in situations where electricity systems face the connection of a large quantity of new generators to the network, as it will inevitably involve the uptake of renewable generation capacities. But the relocation of thermal generators, a continuous process in most OECD countries with old carbon-intensive generation capacities (IEA, 2012b), can also be guided by the same price signals. These aspects will be further discussed in the transmission infrastructure section.

It is obvious that local accuracy in terms of cost allocation and information availability will accompany operational costs for system management and system participation, including the required implementation of risk hedging instruments. Additionally, as the market power of ideally located single generators rises, careful market monitoring becomes more important. This makes assessments between costs and benefits inevitable prior to choosing and implementing one management-type or the other. Based upon such assessments some organized wholesale electricity markets in the United States however, have chosen to implement the most sophisticated management-type *i.e.* LMP (PUC Texas, 2003) as they expected to see the benefits exceeding the costs. Whilst these assessments include some benefits, mostly from an operational perspective, the markets continue to develop to further combine local information with additional network related aspects to maximize the benefits. These added benefits, operational but also long-run benefits, should be taken into account in cost-benefit assessments for identifying the most suitable management type.

Box 2 • Efficient network pricing: Texas going nodal

In December 2010 the ISO responsible for the main energy market area in the state of Texas, the area run by the Electric Reliability Council of Texas (ERCOT), moved from a zonal pricing system to a nodal pricing system. This move was developed over almost six years of stakeholder consultation and software development and implementation.

In Texas, important drivers of the move towards nodal pricing were the dissatisfaction with the zonal market approach and the high levels of wind power. In the ERCOT region the dominant source of wind power is in the west, but there are limitations on the transport of wind energy to the major centres of demand. Given the low capacity factor of most wind generation, networks are designed only to carry a portion of total potential wind output. As such, when wind output is high it becomes more important that scarce network resources be allocated efficiently, in order to allow for an optimally priced generation mix within the constraints of the network.

Benefits from the move to nodal pricing are expected across both short and long term horizons in the ERCOT region. In the short term, a more efficient process of congestion management should allow for a more effective utilisation of existing assets. Indeed, within months of implementing the nodal market in Texas, two early benefits were observed:

- improved management of transmission congestion, with significantly higher utilisation of key network interconnects; and
- reduced capacity procured for the purposes of regulating the market, with a concomitant reduction in costs associated with this.

Long-term benefits should be that new transmission (including HVDC and flexible alternating current transmission systems (FACTS)) and generation investment will be located in the areas where the need is most pressing. It is too early to gauge the impact of nodal pricing on these investment decisions.

Key findings • Cost-benefit assessments should be undertaken prior to establishing sophisticated and accurate market-based management measures. Short-term benefits could arise from network use but also from balancing and reactive power provision. Next to these short-term benefits, such cost-benefit assessments should also include potentially achievable long-term economic benefits. These can become evident with increasing shares of renewables and changes in thermal generation capacities. Costs arise from complex implementation and handling requirements and should also factor in the potential risks of market power.

When network reality gets more complex: local reliability aspects matter

Reactive power¹⁹ imbalances cause voltage levels along alternating current (AC) transmission lines to change, but keeping the voltage level within limitations²⁰ is required for stable network operation. Violations of voltage limitations have already caused severe blackouts in the past²¹ when collapsing voltage levels led to subsequent generator and load disconnections, isolated

¹⁹ Power flows on AC power systems include both active and reactive power. Real power refers to electricity that flows from generation to load to power electrical equipment. It is typically measured in kilowatts (kW) or megawatts (MW). Reactive power is that portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities and is typically measured in kilovars (kVAr) or megavars (MVar). Reactive power consumption tends to depress transmission voltage, while its production (by generators) or injection (from storage devices such as capacitors) tends to support voltage. Reactive power can be transmitted only over relatively short distances during heavy load conditions. If reactive power cannot be supplied promptly and in sufficient quantity, voltages decay, and in extreme cases a 'voltage collapse' may result. With FACTS, the reactive power in a system can be 'adjusted' by means of compensation (e.g. on long AC lines) or additional reactive power can be generated (e.g. with power electronics or synchronous condensers) for voltage support and stability enhancement.

²⁰ Usually voltage drop violations start at 5% to 8% from normal operations on the transmission level.

²¹ If voltage levels drop, protective equipment will disconnect power plants, transmission lines and transformers to protect the physical infrastructure from damages.

systems and system damages. This occurred in the 2003 blackout in the European Nordic Region, affecting southern Sweden and eastern Denmark regions and causing estimated economic costs of USD 310 million (IEA, 2005). Additionally, systems close to their voltage level limits are more prone to system failures caused by even small disturbances. Keeping stable voltage levels is one of the important reliability tasks of a network operator and since reactive power cannot be transported over long distances on the transmission network, the provision has to be local. Currently, in most electricity systems, conventional generators mostly provide reactive power.

Progressions in electricity power flows and renewable generators capacities located far from load centres increase the average transportation distance of power flows. Consequently, reactive power imbalances can arise, which demands more local countermeasures. Another author (Eirgrid, 2011) foresees a potential decrease of over 25% in on-line generator availability for the provision of reactive power. In case of unavailable local countermeasures, the need for reactive power management can lead operators to restrict longer-distanced power flows on transmission lines. Operators can be forced to limit these flows for reliability reasons, which can, comparable to congestion management, reduce the scope and benefits of integrating renewable generation and power flows. This is already the case in Germany where reliability-driven market interventions by one operator²² increased from 2 interventions in 2003 to almost 1 000 interventions in 2011 (Tennet, 2012).

Next to general reactive power availability, the provision requirements for reactive power are likely to become more flexible. The increasing short-term variability of power flows due to the integration of variable renewables will cause short-term reactive power imbalances and reactive power providers must lend flexible support. Historically, reactive power supply was mostly provided by thermal generators as part of the ancillary services²³ and these sources were largely dispatchable. Unbundling has significantly reduced the network planners' influence on generators' locational decision making. This can reduce the creditability of new generators for the flexible reactive power provision at the right location. Additionally, existing thermal generators are generally old in most OECD countries and this will cause relocations of power plants. This can add further reliability challenges at certain locations and to the wider-area network. These changes, if not anticipated by network operators, can cause local imbalances in the reactive power provision. Regarding the German transmission level, local reactive power imbalances in the southwest are caused by the decreasing availability of thermal generators (Figure 6). In the case of an n-1 event²⁴ in these local regions, the voltage levels could start to significantly deviate from the required voltage level.

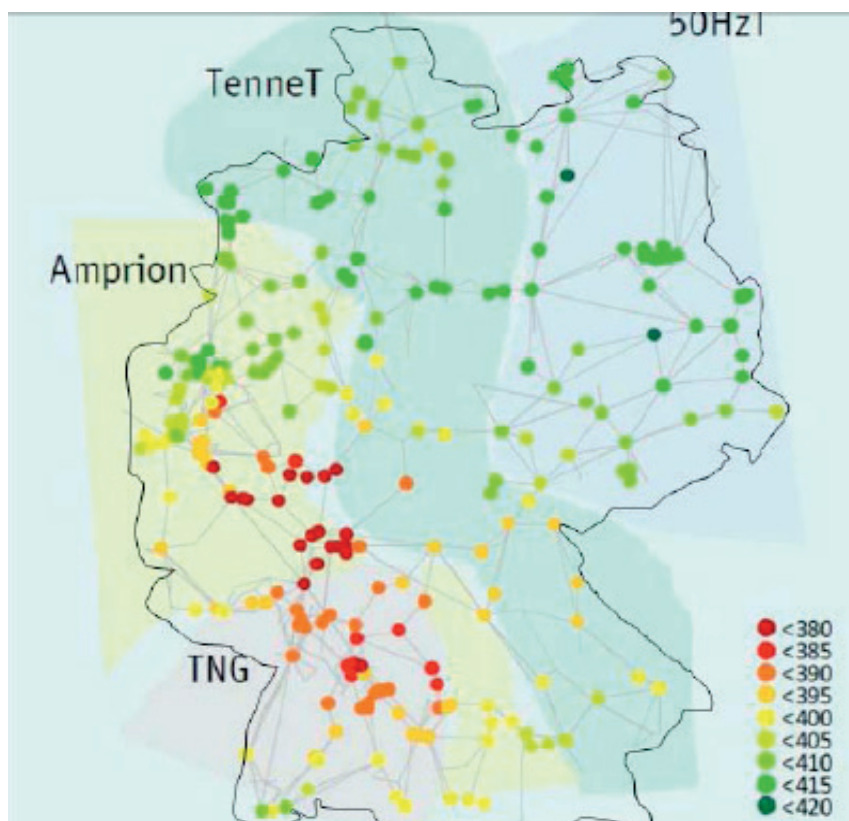
All these changing conditions call for the accurate assessment of the future needs for reactive power. Since reactive power can also be provided by technologies other than conventional generators, it may be beneficial to implement measures to attract the right technologies for reactive power provision at the right location and at the right time. The currently predominant administered obligations on conventional generators (generator connection requirements) for providing reactive power can otherwise become a barrier for market-based decisions to shut down generation capacities (National Renewable Energy Laboratory (NREL), 2012).

²² Germany has four transmission network operators.

²³ as part of the operational reserves.

²⁴ To ensure stable network operations planning for system faults play a major role. In this regard the n-1 planning principle has been established and is commonly adapted by network planners. This n-1 principle is applied to prevent for emergencies with cascading impacts, defined as the uncontrolled loss of a sequence of additional network elements caused by an initial contingency, resulting from the incident of one system component such as a generator, a transmission line or a transformer.

Figure 6 • Voltage level deviations on Germany's transmission network in case of an n-1 event



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: BNetzA, 2011b, EnBW TNG, Amprion, Tennet TSO, 50Hertz.

Key findings • Local reactive power provision ensures system reliability. With larger shares of renewables, there are increasing levels of power flows and generator relocations so changing local reactive power balances will have to be accurately measured. Obligatory reactive power provision can lead to severe market interventions to maintain reliability levels.

Because of its technical complexity, its former local provision requirements based only upon conventional generators and also the lower cost implications, reactive power was, and still is, one of the last aspects of centralised network operations precluded from efficient market-based assessment and procurement measures (Berg, S., 1982). Nevertheless, under the current frameworks the resulting costs of reactive power provision are likely to be inefficient. Potential lower-cost third-party provision is often discriminated by regulatory-rewarded network-based investments (FERC, 2005). To maintain system reliability, network planners and operators undertake demand assessments and supply provisions.²⁵ Costs for the provision are socialised among different network users as opposed to fair cost allocation to the beneficiaries of reactive power management as is the case with specific generators and loads. Under the current frameworks, planners and operators continue to perform such reliability short- and long-term assessments to determine the upcoming undersupplied locations on the transmission system. In situations where countermeasures of diminishing reactive power supply become evident network planners will then tend to favour own network-based solutions, including capacitors,

²⁵ Network operators often use grid access rules requiring generators to be technically able to provide for reactive power, and, in cases where generators or synchronous condensers are unavailable, stationary capacitor banks and static VAR compensators (FACTS) are used.

condensers, static compensators, static VAR compensators (SVC) and AC transmission lines or direct current (DC) transmission systems.²⁶ This can reduce opportunities for third parties to provide more efficient solutions, such as generation-based provision, including renewable generators, or demand response. This behaviour is incentivised by a less innovative approach towards network infrastructure and operations. It can further result from the structural and regulatory frameworks that encourage the asset maximisation of the transmission owner (TO). As competitive business models, including transparent and efficient pricing in particular, are so far unavailable, the missing price incentives do not encourage the uptake of competition by non-network investments.

Key findings • The current arrangements are likely to foster uncompetitive provision and use of reactive power compensation at the expense of all network users.

Academic research (O'Neill, 2008 and NREL, 2012) has encouraged the development of spot pricing rules and long-term procurement and this has incentivised market-based provision of reactive power. Establishing a real-time reactive power price that reflects the market's locational marginal cost could encourage efficient decisions by all market participants in power systems whose demands for shares of variable renewable generation will increasingly fluctuate. It could encourage the lowest-cost suppliers to provide the reactive power, transmission-based technologies, loads and generators, including renewables. Static reactive power equipment in particular cannot switch instantaneously and frequent switching increases wear and tear and reduces the lifetime of the switching equipment. This is noteworthy for real-time pricing systems for reactive power as it enhances the competitiveness of sources, such as static VAR²⁷ compensators, which need finer adjustment so that they can faster react (SIEMENS, 2012). Real-time pricing could also encourage consumers of reactive power to evaluate their net consumption of reactive power, consuming it when the price is lower and reducing their consumption when the price is higher than the value.

Co-optimisation with electricity markets could become a necessity as real and reactive power are flexible and interchangeable products with opportunity costs, at least from a generator's perspective. To a certain extent wind power plants and solar PV plants can also provide for reactive power. Their contribution can be ensured by regulatory frameworks and grid codes, requiring them to contribute to system stability as the added requirement comes at a higher total cost, can ensure their contribution. Germany has implemented incentives for retrofitting existing wind plants to also make use of their reactive power balance potential (BMJ, 2009a). Co-optimisation could also allow the operator to choose the most efficient system dispatch between the provision of real and reactive power (Baughman, M. L. *et al.*, 1997a; Baughman, M. L. *et al.*, 1997b; Berkeley Lab, 2008; O'Neill, 2008; Seifossadat, S. *et al.*, 2009) and when executed efficiently, could lead to significant savings in system-wide costs of electricity supply as discussed in further research (FERC, 2005).²⁸

Accurate pricing methodologies and the development of forward markets, endorsed by regulators and tested and implemented by system operators are still not yet fully understood. Real-life testing at the beginning is crucial for an efficient framework that attracts new methods and technologies (PJM, 2008).

²⁶ As opposed to AC transmission, DC lines do not "suffer" from reactive power increase with growing transportation distance and thus can "transport stable voltage levels" over longer distances.

²⁷ Reactive power is measured in VAR (VAR: Voltage-Ampere Reactive).

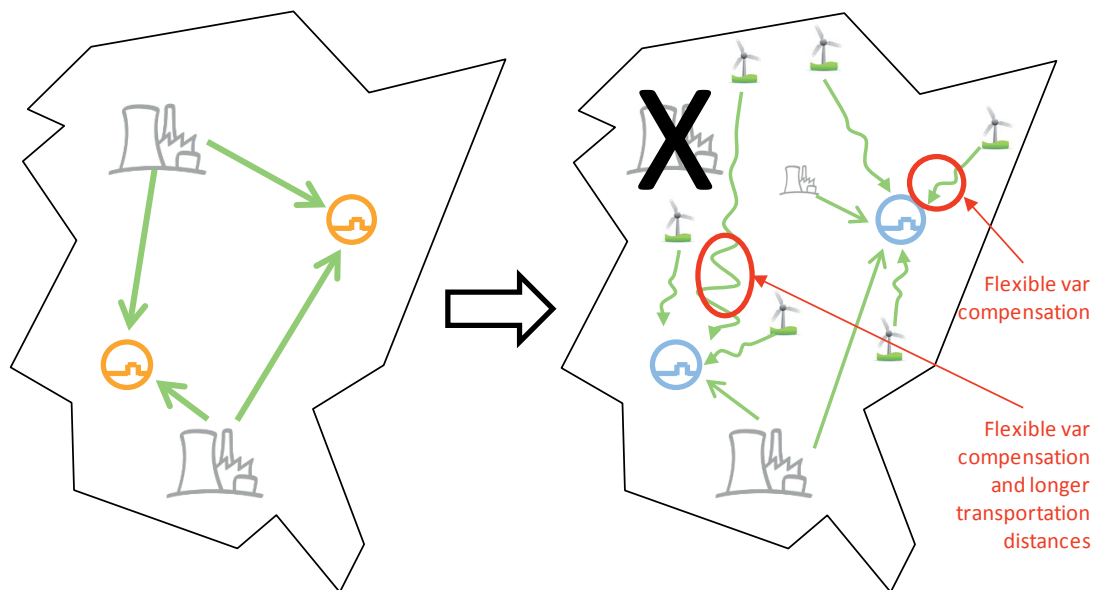
²⁸ Due to the holistic simulation of generation and reactive power provision costs significant dispatch improvements can be possible, as both costs together are minimized.

In general, four important principles should be included for an efficient reactive power market design:

- need for efficient local demand assessment;
- efficient long-term supply procurement;
- fair cost allocation to beneficiaries;
- non-discriminatory supply opportunities with competitive real-time pricing.

Flexibilities exist with renewables' integration into the reactive power balance mix (Figure 7).

Figure 7 • Changing reactive power balances under renewables integration and provision options



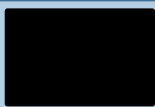
Reactive power balance with renewables integration

• Changing local reactive power balance

• More flexible reactive power supplies

• Unexpected reactive power shortages

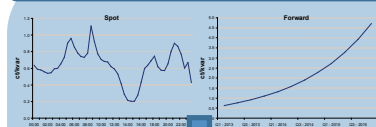
Status quo: black box



- Grid-based technologies;
- Cost inefficiencies and socialization;
- Administered interventions.

or

Open nodal market



- Technological competition;
- Flexible resources;
- Local sufficiency;
- Cost efficiencies.

The establishment of functioning forward markets would be beneficial as they not only allow for risk mitigation of market participants between spot and forward markets but also signal future demand and supply balances for reactive power. Forward markets, as part of the system operations, can avoid situations in which network operators are unprepared for handling changing supply conditions. In cases where generators, driven by age or by increased renewable

generation or power flows, retire and AC electricity flows change and become longer-distanced the local reactive power balances will change. This can lead to operators and regulators having to demand generators to stay online in order to maintain local system reliability until countermeasures are in place. This has been the case in the German electricity market, where an ordinance issued in 2013 gives regulators and operators the task and right to perform system reliability assessments based upon generators' individual plans to exit the market (BMW, 2013). This reliability-based and centralised decision making can arise contrary to the generators' initial business decisions. In these cases, maintaining reliability will require bilateral agreements between single generators and operators, agreements which are likely to cost the network operator²⁹ more and can be prone to the abuse of market power.

However, a more market-based approach will probably lead to implementation and management costs. Compared to the costs of the overall electricity networks, the costs for the provision of reactive power can be small. Therefore it should be carefully assessed if benefits from enhanced operational and investment decision making can justify these additional costs. In cases where the implementation of forward markets is not applicable, network planners should incorporate forward-looking reliability assessments into their infrastructure planning (see the section on infrastructure planning). This can enhance more accurately timed investment decision making for network planners, particularly when generation capacities have relocated. However, the incorporation into planning frameworks may not be a cost-efficient and competitive supply provision as it ignores cost-reflective price signals. This shortfall can continue to favour network-based investments and insufficient financial compensation in cases where reactive power is provided by generators. Even from a today's perspective generally being regarded a small portion of generators costs, insufficient remuneration can contribute to generators' missing money problem, an issue which is also more generally discussed in a study (IEA, 2012d).

Key findings • Efficient coordination between the provision of real and reactive power can significantly enhance system-wide supply costs and avoid regulatory interventions. Accurate market-based methodologies for the provision of reactive power remain subject to further research and testing. In the absence of such markets, open network planning frameworks should be used to facilitate better investment decisions. This can also prevent costly market interventions.

From balancing engineering to balancing markets

Balancing is required to compensate for forecast errors in economic dispatch schedules and thus act as a security valve against involuntary load shedding. So far, the predominant balancing resources are conventional generators, which can provide sufficient flexibility to compensate imbalances. For technical reasons, balancing services are co-ordinated by balancing entities or network operators as they can overlook the status of the total transmission system in real-time and make use of aggregated balancing measures. With the integration of variable renewables, balancing services will be harder in three significant areas:

- increasing levels of forecast errors;
- balancing reserves flexibility;
- maintaining balancing reserve availabilities during “light balancing system conditions”.

Electricity markets and balancing services are physically connected via forecast errors as the more forecast errors an ahead-schedule from the electricity market contains, the more balancing services will have to be used for their compensation. The integration of larger shares of variable renewables will lead to increasing forecast errors. An increasing level of forecast errors will in turn drive the short-term estimation and use of balancing services and long-term need for

²⁹ Such payments are comparable to capacity payments for generation infrastructures.

available balancing capacities. Additionally the demand for immediately available balancing resources can potentially increase in some regions driving the need for flexible balancing resources. Finally, the current market designs surrounding renewable generation can lead to situations where conventional balancing resources are crowded out of the dispatch during some hours, so that they become unavailable for required balancing services. More precisely, the priority dispatch rules combined with feed-in-tariffs are of concern as they interfere with competitive commitment and the dispatch scheduling decisions of other generators and technologies. This can distort market prices for electricity supply and also balancing services, which might otherwise attract investments in needed flexible conventional generation or other balancing sources (RAP, 2013).

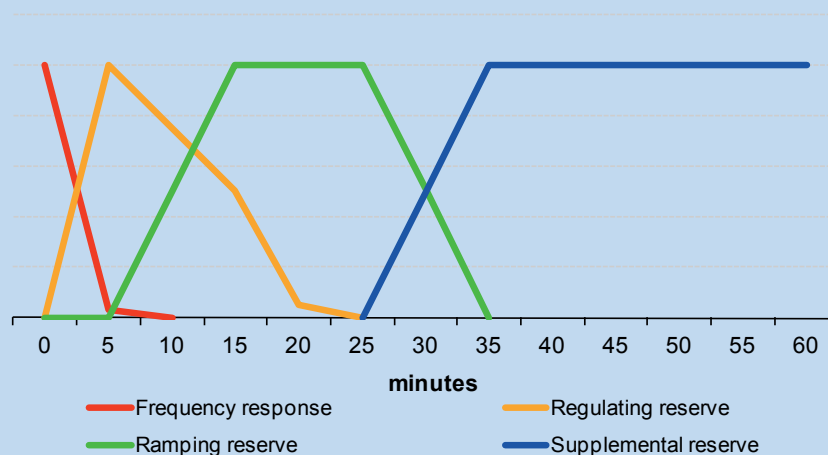
Box 3 • Operational reserves: dealing with the forecast errors

Electricity systems have to maintain the balance between supply and demand in real time to ensure security of supply and power quality. Imbalances between supply and demand will lead to frequency deviations from the required value (Australia and Europe: 50 Hertz, North America: 60 Hertz). Frequency is a measurable indicator for an electricity systems' balance and this indicator is used for the activation of countermeasures to restoring the balance between demand and supply. If uncompensated increasing frequency deviations exceed the thresholds of protective relays on the power system, activated protective relays will automatically disconnect loads and transmission lines so as to contain the frequency deviation within a small region and continue secure operations on other parts of the network. Even with these protective relays in place, avoidance of a cascading failure dissemination, which results in large scale blackouts, is not guaranteed and depends upon the general resilience as well as the real-time state of the electricity system.

Imbalances mostly stem from demand and/or supply forecast errors and/or unexpected system faults. To cope with such imbalances system operators use a variety of balancing reserves, the so-called operational reserves. Their definitions vary between countries and even regions, which makes a perfect global definition impossible. However, similarities exist in the time frame of usage, including activation time, time to full availability and discharging time and this has resulted in classical engineering criteria for differentiating between four key balancing reserves, reaching from very fast reacting and short-lasting reserves to slow reacting but long-lasting reserves.

The initial service (frequency response) is an automated reaction to frequency instabilities (Figure 8). It is provided from all spinning reserves connected to the power system within milliseconds, mostly as financially uncompensated part of the connection requirements. Their provision is limited in time and the reserves will be replaced shortly afterwards by slower-ramping but longer-lasting reserve products, the regulating reserve, the ramping reserve and finally the supplemental reserve. In one way or another, these reserves are financially compensated, often with a capacity payment and volume based payments based upon real usage.

Figure 8 • Operational reserves and their dispatch times



Key findings • Balancing operations handle forecast errors from the competitive electricity market and prevent involuntary load shedding. Demand for balancing services will rise and potentially become more flexible in some regions with growing shares of variable renewables. In addition, renewables' priority dispatch rights and missing exposure to market prices can, if unmanaged, threaten balancing resource availability.

The balancing frameworks currently applied are often administered services where responsible network operators centrally assess the balancing demand and contract the required resources. This demand assessment is based upon historical knowledge of load forecast errors and identified probabilities of generator failures. The portfolio effect of balancing needs is one important benefit from such central approaches. As not all the single entities responsible for balancing demand will require balancing services at the same time, the aggregated demand for balancing resources is smaller as the sum of all demands treated individually. The network operator thus contracts a sufficient amount of balancing resources based upon probabilities of balancing needs at the same time. Depending on the region, there can be established rules on how much balancing services a system operator has to contract. For example, the NERC Disturbance Control Standard requires sufficient balancing reserves to cover the most severe single contingency (NERC, 2012). Very often this requirement is further broken down into various time schedules the balancing providers have to be service-ready.

The availability of these resources is often remunerated by fixed payments with regard to the provided balancing capacity. The remuneration for effectively required balancing service provision is often based upon 15 minutes at average prices or pay as bid prices for each provider. The latter is especially a deviation from the efficient price formation on the electricity market, which uses marginal pricing. So far, thermal generators constitute the predominant sources of balancing services. Costs for the administered provision of balancing services are part of the regulated network costs and tend to be equally socialised among network users. This cost socialisation is unfair to market participants as it shows different balancing-causation. For example, one entity (US DOE, 2000) considers average socialisation of balancing costs an unfair treatment of near-time-invariant loads (such as aluminium smelters) as most balancing costs are caused by other customers. Further, with the socialisation of costs, there is less incentive for balancing-responsible parties to reduce their balancing needs.

Reducing generation forecast errors for cost optimisation

Balancing cost increases will be driven by the increase of variable renewable generation and the associated increase of forecast errors in the ahead-schedule. From single-market experiences, the forecast errors from wind generation can be four times higher than errors related to load uncertainties: whilst the UK system had a load forecast error of 6.9% during 2010, the forecast error for variable renewables was at 28% (Ofgem, 2011). With regard to the increasing balancing challenges of wind integration, NYISO has calculated an increase of average reserve requirements by a factor of 1.5 (CIGRE, 2012) for a system aiming at a 25% share of installed wind capacity from peak demand and this increase is expected to continue with larger shares.

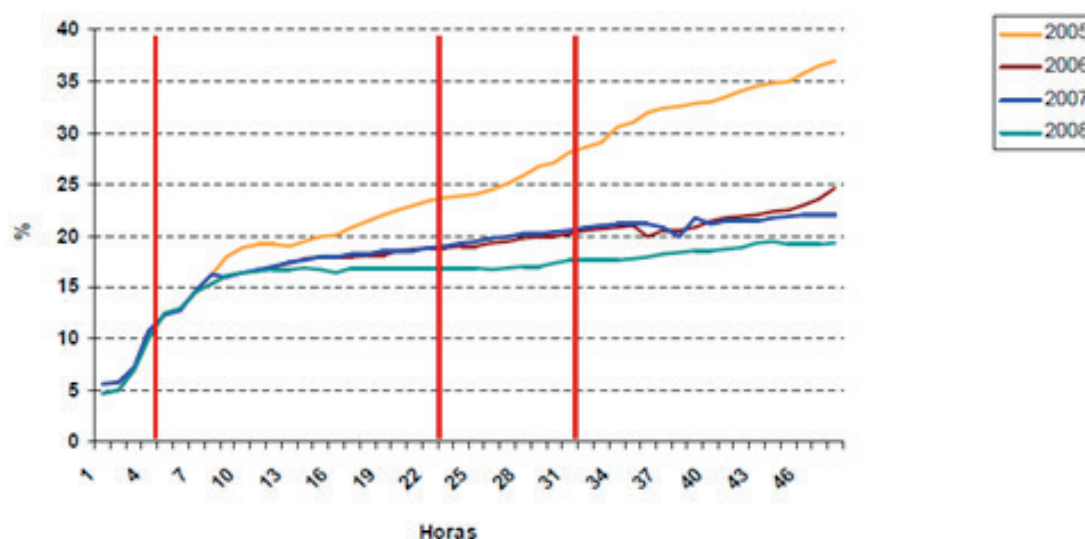
The incremental costs depend on each electricity systems' state before reaching large shares so that the factor of 1.5 is by no means globally representative. A region already inhibiting sufficient shares of flexible sources will be less prone to additional balancing reserve requirements (only to a more frequent or excessive usage), while less flexible systems will have to develop flexibility sources according to their regional requirements and options. This undermines the application of a "one-size-fits-all" approach towards handling the balancing tasks and increases the need for tailored solutions demanded for, and provided by, responsible and competitive market participants.

The level of forecast errors depends on the forecasting horizon: the closer to real-time the more accurate the forecast is. One entity (RED, 2009) provides a general idea of forecast errors and their development over time. Day-ahead schedules include much higher forecast errors and this drives the need and costs for the relatively high provision of available and sufficient operating reserves at the particular scheduling time.³⁰

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As errors decline closer to real-time, bringing wholesale scheduling procedures closer to real-time would reduce the impact of forecast errors (Figure 9). This implies the need for day-ahead schedules to be updated on an intraday basis, where more accurate forecast results for renewable generators can be incorporated into the electricity market schedule and the balancing demand forecast. In this regard, FERC has issued a rule requiring intra-hourly scheduling to minimise forecast errors (FERC, 2010). Australia's National Electricity Market (NEM) already uses a balancing market with a five-minute-dispatch, which is co-optimised with the energy market. Liquidity of the intraday balancing market through low entry barriers to market participants will be one important aspect for maintaining system reliability while fostering cost-efficiency (Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (BMU), 2007).

Figure 9 • Improvement of forecast errors for wind generation over years and hours



Source: RED, 2009.

The benefit of closer to real-time balancing markets is a better assessment of balancing reserve requirements due to reduced forecast errors. Closer to real-time balancing markets can also be seen to better reflect the increasing real-time dynamics of balancing needs which come from the integration of variable renewable generators (NREL, 2012). Applying closer to real-time forecasts and balancing procedures can also help mitigating system faults. This lesson has been learned from an ERCOT 2003 event, where wind ramp rates were sooner and faster than expected in the day-ahead forecast, leading to the depletion of operational reserves (NERC, 2008a).

Improving the renewables generation forecast accuracy in itself could also contribute to less balancing reserve requirements and improved system security. Operators try with several approaches, ranging from centralised wide-area approaches towards localised forecasts. Combining the advantages of both approaches by using a set of forecasts can potentially lead to improvements. Such approaches might also avoid the structural forecast errors associated with

³⁰ This does not necessarily require additional reserve capacity to be installed, as the forecasted renewable generation has replaced generation by existing thermal plants from the dispatch schedule in the first place.

using only one methodology. Amprion and Tennet, two German transmission network operators, apply combined approaches by combining the results of five or more forecasts (NERC, 2010a).

Nevertheless, making the system operator the only liable institution for the determination of balancing demand and the provision of supply sources can potentially be a second best option. As discussed below, single generators will potentially be even better placed to assess their forecast errors, which can result in reduced balancing demand if they are allowed to draw on portfolio effects.

Key findings • Closer to real-time balancing scheduling reduces inherent forecast errors and can potentially reduce the provision and use of balancing services while strengthening system reliability.

Forming efficient markets for assessing balancing demand and supply

Under the current balancing mechanisms there is a lack of market-based incentives for balancing providers to invest into additional balancing capacities, which can deliver the required balancing flexibility (RAP, 2012). If balancing markets develop into a competitive service segment of the overall electricity market, the resulting revenues can incentivise the market entry of new and best use of existing assets to provide the flexibility required to balance variable renewables. Historically, the provision of balancing services was often part of the network connection requirements for thermal generators. The decision to invest in new generation capacities was to a large extent taken without calculating the revenues and benefits from providing balancing services. Until now, demand for new balancing resources has often been saturated. The service providers currently available, conventional generators in particular, often remain available whilst renewables enter the market. Nevertheless, in the medium term these generators can decide to exit the market, driven by the reduced sales opportunities that can change this supply picture. And depending on the initially available generation mix, the balancing services can be limited even more by rather inflexible generators. Finally, with growing shares of variable renewables, the demand for the some types of balancing reserves can increase and this has been acknowledged by various technical studies (IEA Wind Task 25, 2009). (NREL, 2011 and Eirgrid, 2011), which state that, with larger shares of wind, the demand for immediately available spinning reserves³¹ will rise along with that for slower reserves and balancing products for maintaining reliability.

Without taking countermeasures, these developments may lead to balancing resource shortages in the future. More market-based demand assessments and price formation could be applied to attract a sufficient level of balancing service technologies. The efficient formation of the demand side for balancing services remains one of the important challenges to efficient balancing markets. So far, balancing demand remains to be fully assessed by network operators. These central assessments have the benefits of central demand aggregation and the effects of netting out single demand bids (portfolio effect). From a techno-economical perspective however, market participants should be capable in assessing their own technical balancing needs according to their load and/or generation patterns and their opportunity costs. Market participants will likely have better information on their technical needs and their economical costs for self-balancing than operators could ever have. In addition, self-assessments can reduce effects of the otherwise applied conservative approaches by network operators for assessing balancing demand. Therefore a more accurate demand for balancing services can result from this approach and these demands can even be sensitive to the costs of service provision. Cost-sensitivity in this approach would reflect each market participants' willingness to pay for provided balancing services and shows the price elasticity of the demand side. The current practice of deriving more cost-sensitive demand curves is administered by using demand curves for operational reserves,

³¹ Automated frequency reserves as fastest reserves.

which associate different maximum prices to different demand levels. The potential for the formation of more price-elastic administered demand curves for clearly defined balancing products has already been discussed in theory (Hogan, 2012) and was suggested for the potential application within ERCOT. The application in NYISO is already one workable real-life example of applied more price-elastic demand curves in system operations (NYISO, 2013).

As described above, one important advantage of central demand assessment approaches is the portfolio effect of balancing needs, where the sum of all balancing needs is smaller than the individual demands. Combining the advantages of self-assessments in the first step and centrally aggregated assessment with regard to probabilities at the same time may also reduce the resource demand compared to the existing balancing demand assessments.

Establishing forward balancing markets (e.g. as discussed in RAP, 2012) can help identifying accurate future balancing needs and support the adequate valuation of flexibility requirements, especially if responsible balancing entities directly act on the demand side as described above. In electricity generation, efficiently designed forward balancing markets can inform on both potential balancing providers about expected shifts on the demand and supply side and potential market opportunities.

An efficient price formation can further attract service providers and the most competitive technologies. So far, balancing services can suffer from a mismatch of required services and available bidding blocks for these services. Under the current balancing mechanism balancing services are often requested in 5 to 15 minute bidding blocks with average prices, but this can ignore the existence of, and need for, much shorter-termed technologies and products. This discriminates the potential uptake of new technologies, which have comparative advantages in the provision of one or more balancing product(s). This is true at least for the frequency response and regulating reserves, which react within fractions of seconds or minutes and will be replaced shortly after, so that even a five-minute bidding block excludes specified providers from the market. Additionally, the five-minute bidding block will also average out provision prices. The real cost for the provision of balancing services will depend highly on the technologies' total costs and on other potential uses, such as electricity or reactive power markets (Figure 10). An average five-minute price can potentially be too low and thus undermine the incentives of potential new technologies. It is thus likely that shorter termed bidding blocks with undistorted price formation can help promote the business case for new and more suited technologies for single balancing tasks.

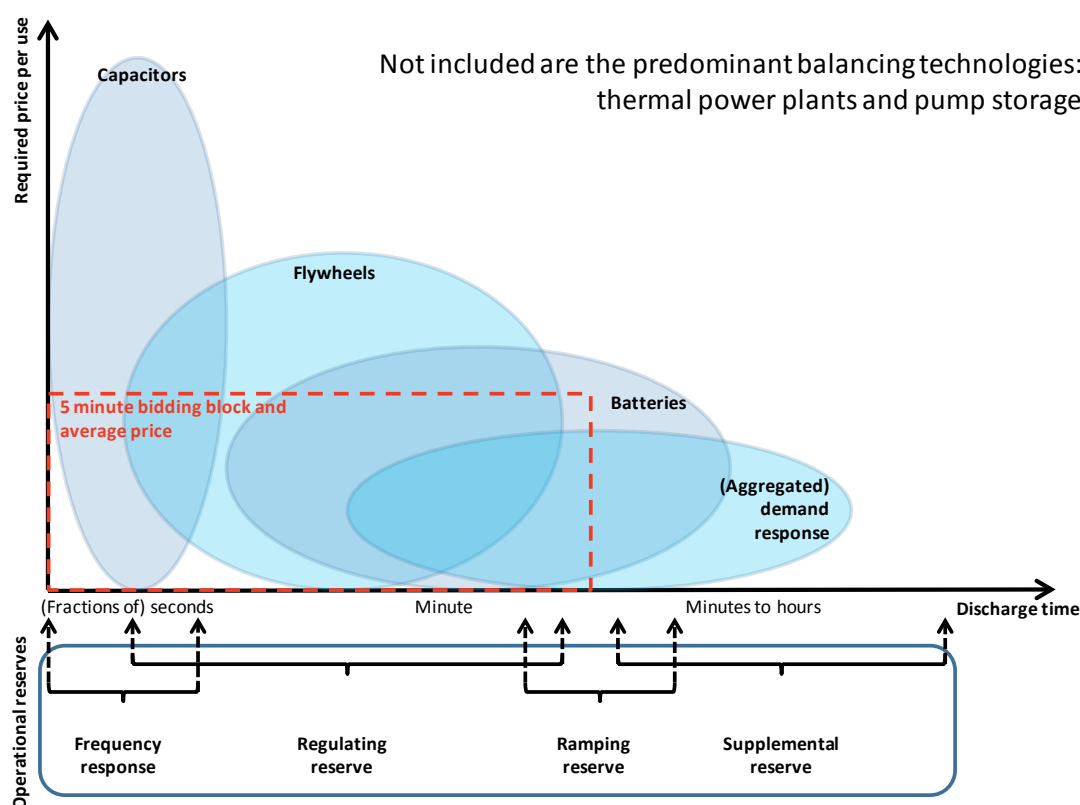
An undistorted and short-term price formation can potentially enhance competition for new and/or additional balancing reserves such as generators, capacitors, flywheels,³² storages and demand response. These aspects have been acknowledged by FERC (FERC, 2011e) as relevant barriers to be overcome for the uptake of more market-based investments and service provision. In the absence of such prices, which would have to be formed within time frames much shorter than 5 minutes, FERC has chosen to introduce capacity payments for developing short-term and mostly non-thermal balancing resources. The uptake of demand response to providing balancing services is also targeted with an ongoing framework review in Australia (Australian Energy Market Commission (AEMC), 2012b) where next-to-product definition and undistorted price formation and the establishment of independent aggregators as a new category of market participants for non-energy services is encouraged.³³ The establishment of an efficient price

³² These can provide large amounts of capacity in a short time scale but only for a limited amount of time.

³³ On behalf of the customers, such independent aggregators would form the real-time interface between loads and the financial and physical requirements of balancing markets, and this is envisioned to making aggregated demand comparable to generators in the market. Benefits from the customers' perspective are reduced transaction costs for active market participation due to economies of scale.

formation with forward markets can potentially avoid an increase in the need for administered decision making and regulatory interventions for disseminating new and/or additional balancing technologies, *e.g.* through capacity payments. As widely accepted in theory and practice, undistorted price formation in balancing markets can also significantly reduce the generators' existing missing money problem (Hogan, 2013; Brattle, 2012 or Joskow, 2006b).

Figure 10 • New balancing providers' discharge times, bidding blocks and operational reserves time frame



With regard to existing transportation limitations and costs of network use, it may be relevant that balancing markets factor in local network constraints and costs for compensating network losses. This can lead to improved operational decision making as well as attracting new balancing sources at the right location.

Finding an efficient mix of future required balancing resources, either existing, new and/or to be built, so far remains subject to intense discussions between policy makers, regulators and market operators as balancing services can be provided from a wide range of sources. As balancing resources can often provide for other services, such as normal electricity generation or reactive power, they can also suffer from congestion at certain locations on the network, which renders the determination of a cost-efficient balancing provision at the right location an almost impossible task for regulators and/or operators. These players will inevitably face lacking information accurate short- and long-term decision making. In addition, a regulated solution can be prone to subsequent revenue inadequacies as with market oversupply or wrong technology choices, which can create oversupply and subsequent underfunding. In view of this, finding the correct set of balancing contributors such as different storage types, demand-side response, flexible generators with low minimum load requirements or transmission should become subject to regional market forces. Establishing a market-based solution should have priority in order to reduce the insurmountable task on network operators or regulators to determine the accurate

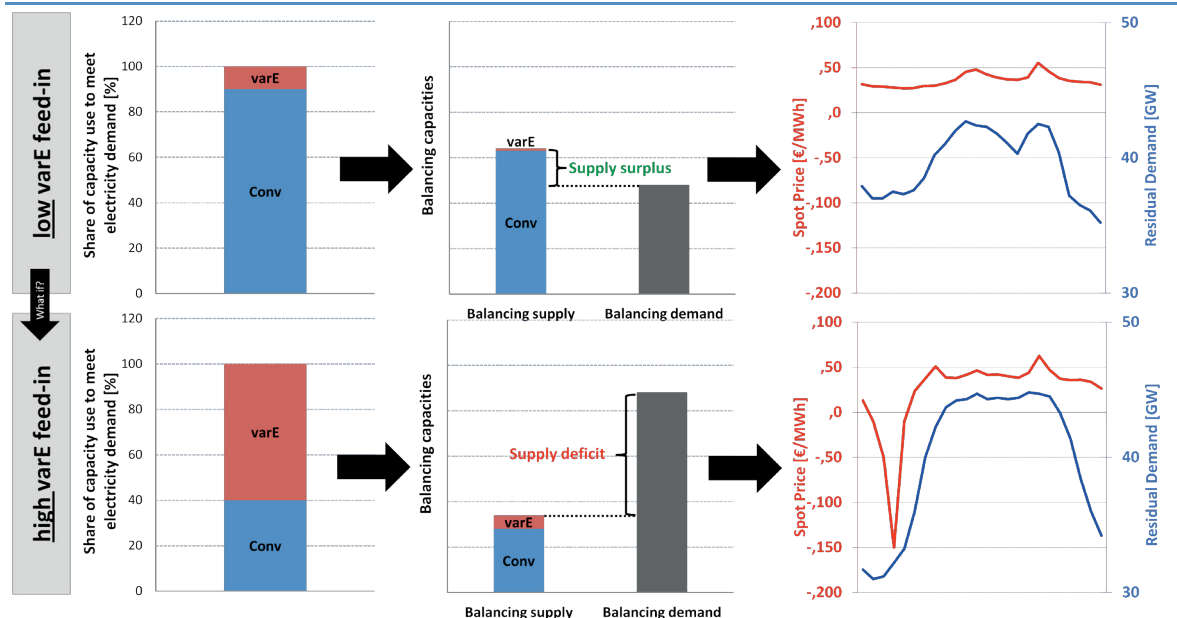
set of technologies. Nevertheless, central operators or emerging independent aggregators will have an important role in aggregating single balancing demand bids to realise the portfolio benefits of netting out negative and positive bids for the same time frame. To acknowledge transportation limitations, but also to prevent unreliable spill overs between markets (electricity and balancing), it may be necessary to co-optimize balancing and electricity markets on approaches, which factor in local network constraints.

Key findings • Fully efficient balancing markets remain to be established through research, testing and implementation. Next to undistorted price formation and close to real-time, the direct demand side formation and localised product accuracy in the short- and long-run are also significant elements of efficient balancing markets.

Variable renewables and their impact on balancing operations

From a technical perspective,³⁴ larger shares of variable renewables can create “light balancing system conditions” – system conditions where available balancing reserve capacities fall below a level required for the sufficient provision of balancing demands in real-time or the ahead schedule. These “light balancing system conditions” will primarily occur at times of high feed-in from variable renewables or at times of low demand, where a combination of both (high renewables/low demand) crowds out most of the thermal generators.³⁵ This consequently leads to a supply deficit of thermal balancing capacities in real-time and through the required restart times of thermal generators even in the ahead-schedules. In this regard, the priority dispatch and missing market exposure renewable generation enjoys is counterproductive for system reliability. In order to avoid balancing supply deficits two solutions, administered curtailment and renewable generators’ self-management are possible. Whilst only the former seems to be applied at the moment the latter can offer the benefits of efficient solution finding in both the short- and long-run.

Figure 11 • Balancing deficit and spot price with renewables feed-in (“light balancing system conditions”)



³⁴ outside the discussion on ensuring a sufficient level of flexible resources.

³⁵ also understood as low residual demand or low net load (demand minus variable generation).

Under the current market arrangements, administered curtailment of “excess renewable generation” will have to be applied by operators to maintain sufficient levels of balancing resources. Operators must be aware of the potential for “light balancing system conditions” (Figure 11).

Operators have to be prepared and capable for the curtailment of “excess variable generation”, implying direct control over variable renewable generators, which is not necessarily the case for all connected plants. The frequency and scope of such reliability-based market interventions by renewable generator curtailment will rise with increasing shares of variable renewables (Eirgrid, 2011) and is already visible in some regions. Administrated curtailment of renewables can be found in Bonneville Power Administration (BPA), Idaho or in Germany, Spain and Ireland, where a required level of thermal reserves is maintained by administered curtailment of wind or the relief from the obligation to buy electricity from wind power plants in times of low demand (BPA, 2012; Eirgrid, 2011; de la Torre, M *et al.*, 2012; Bundesnetzagentur [BNetzA], 2011a and PUC Fortnightly, 2012). In fact, among other reliability measures requiring renewables curtailment, avoiding light balancing systems had the largest impact on total renewables curtailment in Spain in both 2010 and 2011 (de la Torre, M *et al.*, 2012).

Key findings • Priority access for, and missing market exposure of, larger shares of variable renewables drives light balancing systems. In the absence of efficient balancing markets and renewables participation, operators have to curtail excess generation to avoid light systems and maintain reliability.

However, missing curtailment accuracy, especially if curtailment levels rise with increasing renewable generators on the grid can challenge such administrative measures. Questions will arise about which generators should be curtailed, what sort of reference signal, how to ensure equal treatment among all generators and how to co-ordinate between electricity and balancing markets.

Undistorted electricity price formation would allow generators to bid in with their opportunity costs. The inclusion of opportunity costs will reduce market prices below zero (negative prices) when balancing system conditions become “light” as renewable generators can have financial incentives for continuous electricity production even at market prices below their marginal generation costs. These incentives relate to generators’ opportunity costs associated to fully ramping down production and these opportunity costs mostly arise from three factors:

- short-term expectations about otherwise foregone favourable market situations in the future;
- future supply and balancing obligations including penalties for non-delivery;
- costs of cycling, shutting down and ramping-up again.

In electricity markets with possible negative price formation,³⁶ these prices indirectly reflect the balancing system status in real-time. Allowing for price negativity could be one prerequisite for reliability-based curtailment using the indirect signal from the electricity market.³⁷ Using electricity prices, however, is only second best since the spot price formation includes several opportunity cost components and reflects more than the balancing market conditions. Using undistorted real-time prices from balancing markets will be the accurate signal if curtailment is required for balancing supply preservation. Nevertheless, even with an accurate price level (either on the electricity or the balancing market) operator-based renewable generation curtailment is only a second best option from an economical perspective. Due to the variety of generators and each generator’s differing contract obligations, the generator’s opportunity costs

³⁶ Often electricity market prices are capped at a zero price level.

³⁷ Negative electricity market prices can be found throughout organised electricity wholesale markets in the United States and the Nordic power market, but also in Germany where bids down to price levels of EUR -9.999 /megawatt hour (MWh) are possible.

will be almost generator-specific, which makes system-cost³⁸ minimising curtailment an impossible task for a central operator. Only generators will precisely know their opportunity costs, which consequently demand the generators' active participation in the balancing market. However, there is currently no scheme where all generators, including renewable generators, are incentivised to automatically avoid "light balancing system conditions" as a reaction to their exposure on balancing market prices. This can demand testing and implementing market-based balancing approaches. These approaches can avoid administered decision making on curtailment and replace such approaches by a self-managing system with the potential for cost minimisation between balancing services and electricity prices. In addition, such market-based approaches could also foster the identification of efficient investments into balancing resources.

Key findings • Centralised curtailment of excess renewable generation is the current response for preventing light balancing system conditions. So there are no opportunities for more economic self-management by the numerous amounts of renewable generators or for efficient price formation from attracting sufficient balancing resources. Cost exposure of all balancing responsible parties, including variable renewables, to efficient balancing prices will be required but such regulatory frameworks must still be developed and implemented.

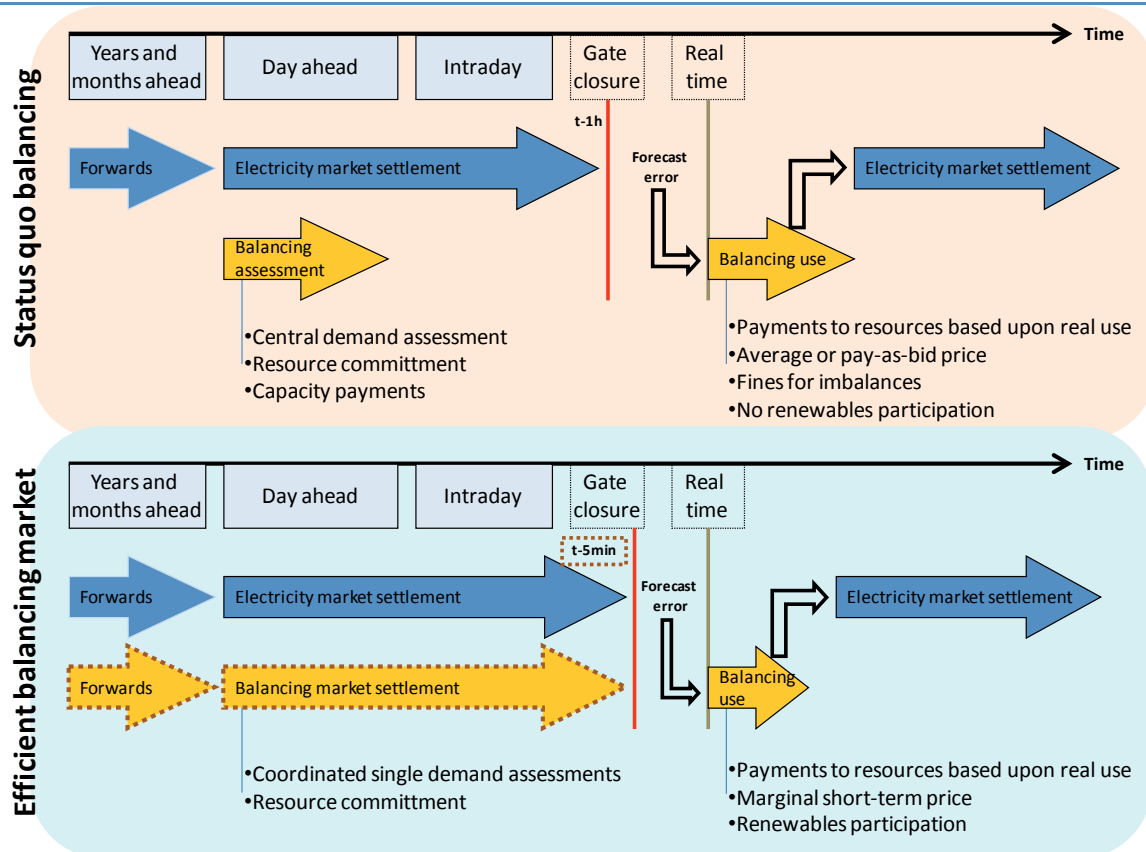
Summing it up: potential advantages of efficient balancing markets

A first disadvantage of common balancing markets can be the routine day-ahead balancing resource assessment. As shown above, this is particularly relevant with the integration of larger shares of variable renewables. Therefore it can be beneficial to use intra-day rather than day-ahead balancing assessments to minimise the forecast errors. A five-minute ahead balancing assessment that draws upon the results from the electricity market bids, as applied in Australia's NEM, seems to be the current best available practice. Such close-to-real-time assessments can reduce the needs for balancing resources. These assessments can further potentially reduce the needs for generally required balancing resources. In cases where electricity markets also run with five-minute dispatch schedules, the total time frame for balancing markets can be limited to these five minutes. Forecast errors only remain for five minutes in the electricity market and will then be compensated by new demand and supply bids at another price level.

A disadvantage of the so far predominant balancing services is that balancing responsible parties, loads and generators, are often not fully incentivised to behave efficiently (Littlechild, 2012). Sometimes administered fines apply to balancing causing parties and this can limit the incentive to draw on balancing services. Fixed fines can be inaccurate in allocating the balancing efforts as they do not necessarily match the opportunity costs of each entity for balancing. If the fines are lower than opportunity costs for the self-balancing of an entity, this entity would rather choose to draw on balancing resources and pay the fines. If the fines are higher than the opportunity costs, keeping the balance could become an additional cost burden for the entity. Therefore it can be beneficial to establish a real market price for balancing services, which is a result of the marginal costs of the marginal service provider. Balancing causing entities should be exposed to these market prices when they create imbalances. Well-designed balancing markets must ensure that single (renewable) generators and loads are not being discriminated against because of their inability to draw on existing portfolio effects, market products and/or product liquidity (Figure 12). Further detailed assessments, for example as currently being undertaken by Ofgem, can help to determine the role of operators, independent aggregators and the possibility for market participants to provide for, and choose from, all balancing options - ranging from self-balancing to bilateral balancing contracts and to operator-based balancing (Ofgem, 2011c).

³⁸ The system costs will be the value of generation, including all supply obligations and future revenues, the costs for the provision of balancing services and those associated with network usage (capacities, losses, reactive power).

Figure 12 • Balancing services today and efficient balancing markets in the future



A further disadvantage is that balancing resources are often not attracted by efficient real-time market price for balancing services and missing demand and supply information in the long run. Unlike the competitive electricity markets, prices for balancing supply are often average prices instead of marginal prices and these prices can lead to a continuous shortfall in remuneration required for covering total balancing service costs, including operational and capital costs. The behaviour from system operators can dampen the balancing market price during scarcity events, by often reducing voltage levels (brownouts) to avoid curtailment or by buying out of the market supplies (Joskow, 2006b). This price formation and uncertainty does not necessarily attract new balancing resources as it limits the potential for inframarginal rents. Applied average prices or pay-as-bid prices do not necessarily reflect the supply costs during all times. Increased certainty about supply and demand in the medium term can inform and attract new balancing resources when required. Efficient price formation for short-term service provision, as acknowledged by FERC (FERC, 2011e), can create a competitive environment for the numerous available balancing technologies. In the absence of such prices, which would have to be formed within time frames shorter than five minutes, administered decision making and continued capacity payments can remain the only available option for attracting sufficient balancing resources.

This problem is more prominent with investments into new generation capacities as discussed as the “missing money problem”. Investors in new generating capacity expect to cover total costs, including their capital costs from electricity sales and balancing provision. Independent of the technology, the problem remains the same for all these technologies.

Despite the mechanism to attract new resources, demand should always be assessed on local conditions. In cases where balancing demands are located behind congestion, the balancing resources have to adjust accordingly.

The final disadvantage of the existing arrangements is the interplay between renewable generation and the existing balancing resources. To avoid situations where excess renewable generation crowds-out required balancing resources, administered curtailment is currently the only available option. With more market-based solutions, such curtailment could be replaced by self-management of all balancing causing entities. If these entities, including renewable generators, are exposed to efficient prices on the balancing market, they will adjust their balancing demands accordingly. The resulting price levels on the balancing market could potentially also incentivise new investments into balancing resources, but this would require price formation more often than every five minutes.

Key findings • Balancing services are still centrally administered solutions with inefficient price formation and no direct demand-side participation. Efficient market-based solutions can potentially offer better economic efficiency and attract new balancing resources. Accurate price exposure can also avoid centralised curtailment of renewable generation by operators.

Enhanced awareness and management

Decisions taken by system operators to maintain reliable network operations can only be as good as the underlying information available to the operators. Better knowledge management incorporated into closer to real-time operations can contribute to maximising the utilisation of already-installed network capacities. Today, most operational decisions are often ex ante power flow analysis based on the supervisory control and data acquisition (SCADA) systems with regional scope. This predominant approach to system operations has provided high reliability levels in the past where electricity flow paths from centralised generation capacities were largely foreseeable and less inter-regional. However, the integration of longer-distance power flows and variable renewables has, and will, continue to change the level of predictability of power flows across the system. Depending on the underlying infrastructure, these power flows can lead to more rapidly changing system states that could exceed reliability thresholds on local voltage levels and reactive power balances, line congestions and balance demand and supply. The effects of longer distanced power flows, increasingly also coming from variable generators, will also have to be accounted, which could increase demand for wider-area and inter-regional recognition and management systems.

The latest, often applied, approaches for system operations and management include longer-term (ex ante) assessments of forecasted power flows across electricity systems. As these flows become more uncertain with the growing influence of variable generation (IEA, 2013), the growing forecast errors could require growing portions of existing system assets, grids and generators to be kept available and more management. To reduce forecast errors, closer to real-time network monitoring and management would have to become the rule rather than the exception, which can free up otherwise blocked system assets. In addition, close to real-time monitoring and management capabilities can become a relevant tool for maintaining reliability at current levels, as reliability thresholds can be breached more dynamically. Examples from Spain, Coordination of Electricity System Operators (CORESO (CORESO, 2009)) and TSC (TSC, 2011), demonstrate the general awareness to move system operations closer to real-time (Box 5).

Even though the “North America case” resulted from missing awareness due to IT failures in the control room and the relevance of keeping monitoring and operating systems close to real-time is clear (Box 4). As the more dynamic power flows from renewable generators increase on the system, the closer to real-time the monitoring and management cycles must become. The likelihood and impact of, as well as preparedness against, such increasing levels of system dynamics are so far not openly discussed between all relevant stakeholders so as to identify the most suitable and cost-efficient solutions. Discussion between transmission and distribution network operators, suppliers and generators’ regulators, at policy and other relevant levels, will

be required to enhance understanding of the situation and find solutions. In this vein, the IEA work on the ESAP is relevant to IEA countries, as one of the five work streams will support the implementation of comprehensive peer reviews of electricity security and emergency management arrangements in these countries (IEA, 2013).

Box 4 • The price of missing awareness: lessons from the 2003 North American blackout

Missing awareness over power flows can have significant impacts and lead to widespread and expensive blackouts. This has been experienced for example in North America, where the regions' largest supply disruption hit the Midwest and Northeast of the US and the Canadian province of Ontario in 2003.

At the beginning of the blackout erroneous input data rendered the state estimator of the Midwest Independent System Operator (MISO) ineffective. The state estimator and real-time contingency analysis tools were effectively out of service between 12.15 pm and 4.06 pm. Without an effective state estimator and with its normal automatic operation disabled until 2.40 pm, MISO could not perform effective contingency analysis within its reliability area, preventing timely 'early warning' assessments of system status and reliability. This missing awareness initiated a trip of a relevant generator on the network, which subsequently led to further and cascading line tripping and resulted in involuntary load shedding. The entire Northeastern United States and eastern Ontario then became a large electrical island separated from the rest of the Eastern Interconnection. As a result, the large electrical island in the Northeast had less generation than load, and was unstable with large power surges and swings in frequency and voltage. Subsequently, many lines and generators across the disturbance area tripped, breaking the area into several electrical islands. Generation and load within these smaller islands was often unbalanced, leading to further tripping of lines and generating units until equilibrium was established in each island or they blacked out.

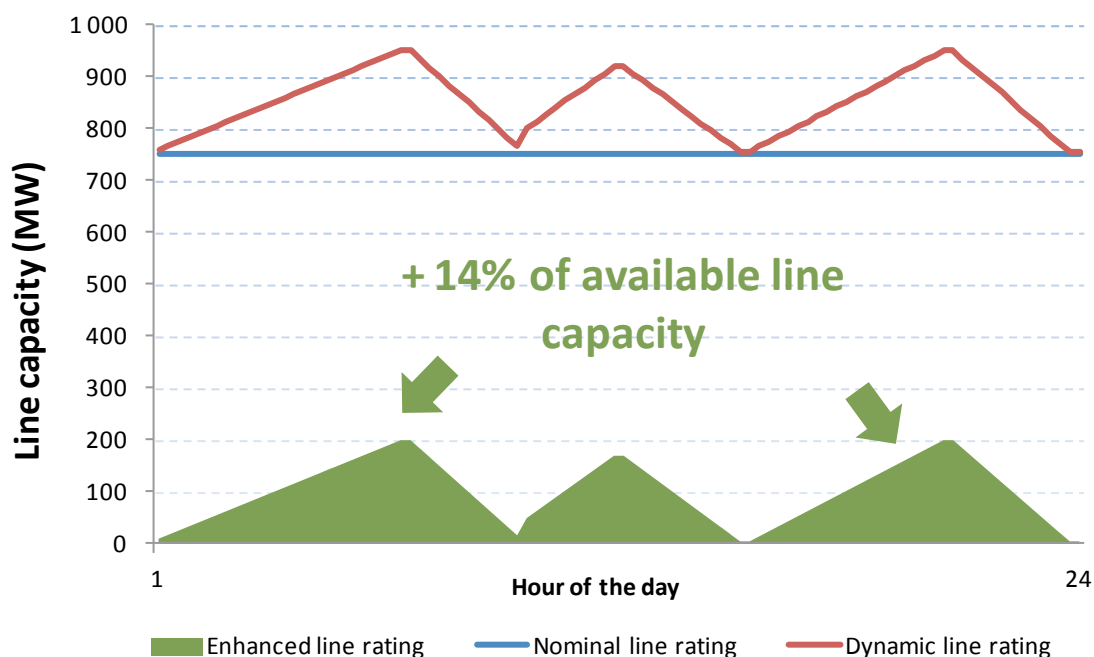
Once the regional cascade was complete, large portions of the Midwest and Northeast United States and Ontario, Canada, had been disconnected. At least 265 power plants and over 500 individual generating units had shut down. Overall, 61 800 MW of load was lost in the states of Ohio, Michigan, Pennsylvania, New York, New Jersey, Connecticut, Vermont, Massachusetts and in the Canadian province of Ontario. Around 50 million people were disconnected initially. In the United States, the economic cost of the disruption has been estimated at between USD 4 billion and USD 10 billion. In Canada, gross domestic product fell by around 0.7% in August, with 18.9 million working hours lost and manufacturing shipments down by CAD 2.3 billion.

Key findings • More dynamic power flows can create significant forecast errors over power flows during commonly applied monitoring periods. Examples from the past show the potential negative impact of such errors, missing awareness and management capabilities. Stakeholders should identify relevant and cost-efficient operational countermeasures to avoid such blackouts and an over-reliance on underutilised back-up infrastructure.

Monitoring and operating more dynamic power flows under the predominant methodology can not only become a challenge for system reliability but it can potentially also lead to a reduced capability of power systems for renewables integration. System operators continuing with ex ante assessments will determine a level of acceptable power flows, which do not exceed pre-determined operational reliability thresholds. However, such assessments omit the assessment of reliable power flow potentials in real-time and these potential flows can be significantly higher. The reason for this is found in various external factors influencing the available network capacity and system stability in real-time. Comparable to generation for variable renewables, these external factors can never be accurately assessed ex ante and are therefore often conservatively assessed based on a "worst-case" scenario. In situations where parameters only reach levels below the "worst-case" threshold, the theoretically available network capacity can remain underutilised but some levels of power flows will be curtailed.

New monitoring and operating devices as well as control software of wider area measurement systems (WAMS) can deliver real-time system information of highest accuracy. Phasor Measurement Units (PMU), high speed sensors placed throughout the network, can help transform the steady-state assessment of larger electricity system regions to real-time measurements, revealing the dynamics of power flows on a wider and meshed power system. Awareness of the system's real time system status increases the use of existing network assets and operates the networks closer to its real limits without endangering reliability. Such systems can further contain system failures to smaller regions and thus prevent cascading blackouts.

Figure 13 • Temporal variation of available line capacity over a typical day



Monitoring and managing networks in real-time via “dynamic line rating” (DLR) can make maximal use of existing assets (EPG, 2006). This becomes increasingly interesting in regulated markets demanding cost-efficiencies and also reduces the need for new transmission and thus, partly solving local acceptance problems (see the infrastructure siting discussion in the following section). A practical example of DLR can be found in Texas, where the system operator ERCOT measured real-time weather conditions around transmission lines to determine the usable transmission capacity.³⁹ Applying DLR to existing lines has brought the benefits of congestion cost reductions in the balancing market and re-dispatch operations in the ERCOT market. Academic research (Hur, K. *et al.*, 2010) estimated the cost savings of DLR from 2005 to 2006 to more than USD 100 million. One study (EPRI, 2011) states that experiences with dynamic ratings typically lead to a “capacity increase” of 5% to 15% of the existing installed networks.

Key findings • Increasing power flow dynamics can be handled via state-of-the-art real-time monitoring and management capabilities. Such technologies can additionally set free back-up network and generation assets. Increased asset use can be beneficial for integrating renewable, support electricity markets and deferring or avoiding additional network investments and associated not in my back yard (NIMBY) problems.

³⁹ With increasing temperature on a transmission line, the lines are increasingly sagging. Sagging lines are widely known as one key reason for line faults and blackouts. The common approach is to apply the maximum ambient temperature of a region for the system operation during all times (thermal rating). Due to changing weather conditions (wind, solar, etc.), it is mostly the case that dynamic thermal ratings are below the fixed nominal ratings.

Whilst WAMS and PMU will ensure a detailed overview in real-time over a wider network area, the challenge is to act on the flow information. Certainly, FACTS⁴⁰ can allow for almost real-time management of power flows, voltage levels or other stability characteristics and are electronic-based systems and other static equipment that provide control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability. With the integration of larger shares of variable renewables, FACTS can be especially helpful in case of sudden power flows appearing, changing or disappearing at certain nodes or over a wider area. Standard applications like SVC, Thyristor Controlled Series Compensation (TCSC) and fixed series compensation (FSC) offer a very good cost to performance ratio and are based on a highly mature technology. Thousands of these systems are used worldwide. However, some special purpose systems can be costly and some of the devices need further technological and cost improvement. Their value can increase over time with continuous renewable integration, when power flows and voltage levels require real-time awareness and handling for maintaining system reliability.

Box 5 • Overseeing the system: the Spanish CECRE

Renewable generators' dispersion and varied nature make it necessary to increase the attention and readiness to act of power system operators. In order to allow an efficient penetration of renewable energy whilst guaranteeing system reliability, the monitoring, control and real-time communication between system operator and renewable generators is important. This delivers real-time awareness over renewable generators' conditions, enhances operational variability and supports necessary instructions relating to their production conditions. The Spanish Control Centre for Renewable Energy (CECRE) is a global pioneer scheme of a renewables control centre, which checks the renewables' state in real-time every 12 seconds with the aim of maximizing their system penetration. The CECRE, operational since 2006, allows the incorporation of real-time information coming from the renewable energy facilities larger than 1 MW into real-time power flow analysis. In light of this, CECRE supervises all commercial wind as these were generally built in clusters and 60% of the solar PV generation occurs in Spain (de la Torre, M. *et al.*, 2012).

To embed CECRE and the associated renewables production into the overall electricity system, there is a suitable communication connection with the Spanish transmission system operator (TSO) general system control centres. This communication connection secures the liaison with RED, the Spanish TSO, and renewable generators at all network levels during all times. Based on real-time power flow analysis, if it is detected that there is a restriction solvable only by limiting renewable generation, the CECRE sends set points to renewable generators larger than 10 MW to automatically adjust their generation. So far, such restrictions can come from insufficient fault ride through capabilities of the available generators, network congestion or light balancing system conditions. This assessment and management process is repeated every 15 minutes and the renewable generator management capabilities support the TSO to re-establishing n-1 secure situations within short time frames. This is seen as crucial element for maintaining system reliability and it substitutes most off-line operations for on-line real-time criteria leading to enhanced integration while maintaining system security. CECRE has so far facilitated reliable system integration even up to high levels of renewable penetration at 64% of system demand on September 24, 2012.

Identifying the future needs of such awareness and management systems, their specific benefits for the whole electricity system and its consumers and also the associated incremental implementation and management costs, can help identify sound applications. Further technological testing seems to be required in several cases. From a regulatory perspective, split incentives can exist as operators can prioritise operational cost reductions against the maximisation of network capacity usage and the further integration of power flows and renewables. Efficiently designed planning and regulatory frameworks should try to incentivise the

⁴⁰ Facts devices can be installed in a substation, requiring less space and permitting than additional transmission lines.

identification of cost-efficient technologies with regards to system-wide cost minimisation as it is discussed in the sections on transmission infrastructure planning and regulations. Regulatory frameworks, which solely incentivise network cost reductions can fail or postpone the implementation of better system management.

Key findings • Real-time awareness and management can become increasingly important for the cost-efficient integration of power flows and renewables whilst maintaining reliability levels. Not all required technologies are yet available but regulatory frameworks need to develop to overcome possible investment hurdles.

Transmission network infrastructure

Investing in new network infrastructure for integrating renewables and power flows, facilitating generator relocation and maintaining reliability targets seems inevitable. There seems to be agreement on the need for more transmission investment over the next decades in most IEA regions. Four important investment drivers are usually referred to:

- the integration of renewable electricity sources;
- generator relocation;
- enhanced electricity trading;
- the reliable accommodation of growing demand.

In Europe, where the European Network of Transmission System Operators for Electricity (ENTSO-E) is tasked to identify “community-wide” transmission investment needs via a ten-year network development plan (TYNDP), 80% of the investment needs are related to the direct or indirect integration of renewables. The recently published 2012 European TYNDP identifies the need to invest around USD 131 billion⁴¹ in the refurbishment or construction of roughly 52 300 kilometres (km) of extra high voltage power lines over the next decade. These new lines represent an increase of 17% of the existing network length (ENTSO-E, 2012) and the total investment costs are also in line with IEA projections (IEA, 2012a). In the United States, NERC has identified an investment need of roughly 64 000 circuit km of high-voltage transmission for the same decade, where almost 30% is driven by the integration of variable renewables (NERC, 2010b).

There is still no single liberalised electricity market globally where all new network investments are determined and undertaken by market participants without regulatory support. Customer competition among network providers, solely based upon market-driven revenues (merchant investments), is often impossible and undesirable from an economical perspective. Today, this is particularly true in meshed electricity systems where electricity flows and associated revenue streams are less controllable and thus less foreseeable. For various reasons described further below, such merchant network investments often remain at the margins of transmission systems⁴² and natural monopolies under regulation form the important parts of the infrastructure. Nevertheless, it’s worth allowing merchant investments when they prove to be more efficient. Infrastructure planning frameworks should be established, which form a neutral basis for merchant investment but also rely on regulated investments for the residual. For the residual network, investments remain regulated with the potential implications of economical disadvantages, dependent on the market state, development and complexity, and each regulator’s capacity. Especially in markets with significant changes in the electricity system, e.g. driven by the integration of larger shares of variable renewables, high regulatory expertise

⁴¹ Converted from EUR TO USD at an exchange rate of 1:1.26.

⁴² Those investments are often point-to-point connections by DC links, such as the Australian Murraylink.

and efficient regulatory tools can help to minimise uneconomic investment decisions, otherwise leading to insufficient and inefficient network capacities that threaten integration efforts and economic efficiency.

Information asymmetry will remain one of the main barriers to accurate regulatory decision making, but frameworks exist to alleviate this shortcoming. To mitigate existing, and avoid additional, disadvantages the implementation of five market structures and (regulatory) frameworks may be beneficial:

- The unbundling of investment planning and investments, to ensure each projects' finance, to limit incentives for copper-plating and to better facilitate non-regulated but competing investments such as demand response, storages or generation.
- Quantifiable values for measuring benefits of renewable electricity integration and enhanced reliability, which can be factored into relevant cost-benefit assessments for network investments.
- An open and locally accurate planning framework with opportunities for multi-stakeholder investment proposals, vertical planning outreach to distribution networks and cost allocation to beneficiaries.
- The support of competitive regulatory investments via open tenders for cost reductions.
- The application of incentive-based regulations for facilitating efficient network investments.

New network investments are required in some countries and regions and envisaged in several others. These entail the implementation of comprehensive planning frameworks, which closely co-ordinate information exchange and facilitate assessments undertaken by all relevant stakeholders such as loads, generators, intermediaries, environmental groups, regulators and network planners from the very beginning. Implementing such frameworks as soon as possible could address the investment challenges and also foster efficient decision making for capital intensive and long-lasting investments.

Key findings • Several drivers for new transmission network investments exist, with renewables' integration often being amongst the most significant. In the absence of market-based investments, the planning frameworks with regulatory comprehension and project approval will determine cost efficiency of system development.

Market-based transmission network infrastructure investments

Nowadays, building new network infrastructure is mostly supported by regulation. Regulation offers a solution to the barriers efficient market-based network infrastructure investments (merchant investments) globally face on most investment occasions: uncertainty and potential revenue shortfall. In most IEA countries, regulation compensates actual transmission investments based on revenues calculated by the regulator. In some cases, incentive payments are applied but in others traditional "cost of service" regulations apply (see discussion below). Investments are often based upon a planning regime with incorporated cost-benefit assessments (see discussion below), often including aspects of economics, reliability and other public policy obligations.

Barriers generally existing for merchant transmission investments are precise, but academic research (Joskow, 2005 and Littlechild, 2011), has identified five others:

- market power of transmission investments, leading to non-fundamental price spreads between nodes;
- incentives to maintain price spreads between nodes (lumpiness);
- imperfect market information on capacity requirements, location and timing,

- transaction costs of coordination amongst all relevant market participants;
- long lead times, lack of forward markets and regulatory uncertainty.

However, the existence and influence of each of these barriers seem to be country- or even project-specific and the academic debate is still continuing on the experiences of already existing real-life projects and the resulting policy implications. Single observations with real-life projects have identified imperfect market information as a major hurdle for merchant transmission investments, where expected price spreads between interconnected nodes proved to be lower in practice whilst other barriers were not observed in practice (Littlechild, 2011).

It is worth continuing the identification and potential elimination of barriers to merchant-based transmission investments as one aspect to policy makers and regulators around the world. A potential subsequent increase in merchant-based investments will reduce the need for regulatory tasks to assisting the process where relevant. Minimising regulatory tasks can reduce the five failures inherent (to changing extents) in all regulatory processes (Joskow, 2010):

- imperfect (local) market information;
- slow regulatory adaptation to changing conditions and favouring existing technologies;
- bureaucratic efforts and time-consuming decision making often spanning multiple regulatory jurisdictions;
- inadequate staffing of regulatory institutions;
- political pressure and lobbying.

Compared to regulated investments, merchant-based investments are supposed to enhance overall economic benefits as investments are more accurate in size, technology, timing and location. They can further attract required capital for the facilitation of new investments. Regulated investments may be less effective than a merchant model in providing for the identification of innovative transmission investment options, construction costs minimisation and efficient tradeoffs between generation, demand and conventional distribution and transmission investments.

Only a very few examples of merchant investments exist to date, which makes it impossible to judge the net benefits of merchant versus regulated investments in practice. Nevertheless, the results of Littlechild's initial country-specific project-success comparison (Littlechild, 2011) indicate an enhanced performance from and with competitive investments, which are almost comparable to merchant investments. In Argentina during the 1990s, such competitive investments seem to have delivered an overall cost reduction, a tendency towards innovative technologies as well as shorter lead times from planning to commissioning. These effects have been the results of an applied planning framework, which facilitated open and consultative transmission planning debates and fair cost allocation.

Whilst merchant investments so far remain at the margins of investment, in AC systems in particular, to-be established holistic investment frameworks should allow for merchant-based investments where possible if they are more efficient as the regulated model (Hogan, 2010). In addition, new transmission is only one of the often existing technological alternatives and a holistic and competitive planning framework should encourage competition. Technological alternatives to transmission can be large- to small-scale demand side solutions, generation and storages from other segments of the electricity sector. But also within the network sector, underlying medium- and low voltage networks can be a competitive solution.

Box 6 • Scaling up transmission in Argentina: the Public Contest Method

During the period of general economic and welfare expansion between 1992 and 2002, Argentina also expanded its transmission system by 5 200 km, adding 2.7% of transmission lines annually over ten years (Pollitt, 2008). The scale-up was embedded into an open, transparent and consultative investment framework with low regulatory interventions, the so-called "Public Contest Method" (PCM). The results of this scale-up are often considered a success story with regard to timely, efficient and innovative transmission investments. Another academic study (Littlechild, 2008a) found a two and a half times cost reduction of transmission investments made under the PCM as opposed to being made under regulated federal transmission planning.

Additional findings are a fast tracked scale-up with delivery times of 3.5 years from the initial planning to final commissioning as well as the tendency towards the utilisation of innovative technologies and the utilisation of the full scale of choices. Control systems and transformers rather than extra-high-voltage lines are the focus of important investments, as transformer capacity rose by 21%, compensators by 27%, substations by 37% and series capacitors by 105% (Littlechild, 2011).

PCM was applied to all new transmission investments above USD 2 million. Under PCM, it was not necessarily the incumbent transmission owner proposing new investments but all users. This also implies the incumbent not having a monopoly for new investments in his region. Proposals for new investments could be made by at least 30% of affected users and subjected to a vote of all the affected users. According to Littlechild, the median number of affected users (voters) was five, and the process was generally characterised by harmony between participants rather than by discord, minimising transaction costs. Nevertheless incumbent transmission owners were also allowed to put forward project proposals, which became particularly useful for reliability-related investments.

At the next stage the decided investment would be put out to a competitive tender if less than 30% of the users affected by the new investment voted against it. This vote included a cost allocation of the investments to the beneficiaries of the new transmission project. The tender usually attracted three bidders on median average with the incumbent transmission owner winning less than one fifth.

The PCM also extended down to the distribution level, which ensured a holistic vertical transmission and distribution planning, development and financing approach. Academic research (Littlechild, 2008a, Littlechild, 2008b and Littlechild, 2011) found active participation of professionalised distribution companies in the PCM, leading towards vertical needs' assessments and increased economic benefits through better solution finding.

One of important benefit of the PCM was the encouragement of competitive investments via tenders, as these tenders limited the incentives of an incumbent system planner/owner to benefit from over expansion of the transmission network and offers had to compete.

Nevertheless, the PCM remains controversial to some extent as it potentially favoured under-investments and failed to make anyone responsible for system planning. According to other research (Pollitt, 2008), under-investments could have arisen from the way costs were allocated in detail. Since the costs were allocated to every user of the system by each user's utilisation rates, the heavy users with low or even negative benefits had to pay the most and this influenced their voting decisions. On the same (under-) investment aspect, a further academic study (Littlechild, 2011) stresses the suitability of the PCM to determine only economically efficient investments.

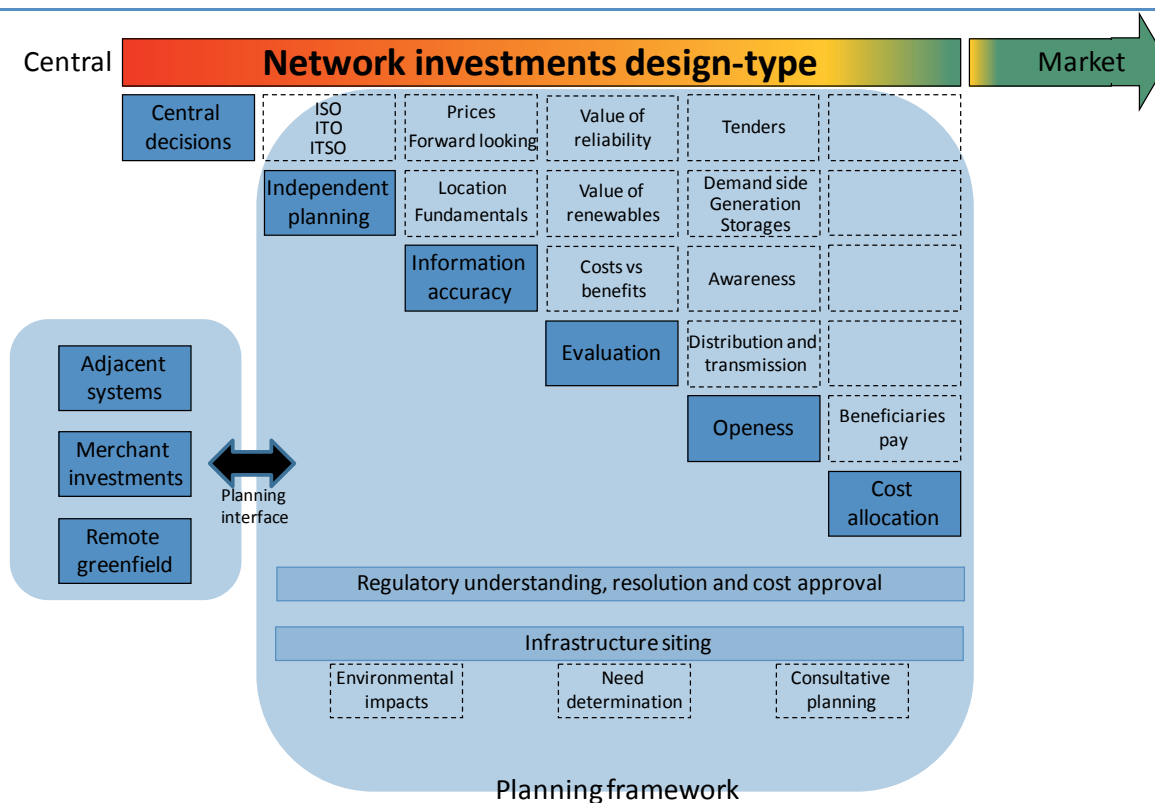
Further critiques include potential free-rider problems after cost allocation, the applicability in radial systems only (as only radial systems show low interdependencies and allow for detailed benefit allocation) and the shortfalls of an unavailable system-wide planning regime where an independent operator chooses from the best system wide options to maximise net market benefits.

Key findings • Market-based network investments show significant benefits compared to regulated investments, but so far also face significant barriers and shortcomings. Meanwhile, efficient frameworks for transmission planning and cost allocation are developing but remain subject to ongoing academic debates and experiences from different real-life approaches. Holistic planning frameworks, allowing for participation of all technological solutions, should be the current development focus.

Facilitating timely and efficient new infrastructure investments under regulation

New network investments in the power sector will be required to maintain reliability and accommodate growing power demand, to enhance power sector economics via power flows, to allow for generator relocation and also for power sector decarbonisation via the integration of renewables. Most of these transmission investments must continue “sufficiently” under regulation whilst generally allowing for potentially more efficient competitive and merchant investments. Any final future transmission network infrastructure will remain subject to the influence of supply and demand changes in location and quantity, political choices, regulatory frameworks, environmental impacts and public acceptance. If increasing demand levels exceed the existing network capacities’ transport capabilities, network upgrades will be required to ensure reliable supply. Should commodity prices for gas and coal change or remain stable (US market) and thus trigger a massive coal-to-gas switch for new generation capacity, then this will significantly affect the transmission system build-up location. Where policy trends towards the inception of large-scale renewable technology clusters, such as offshore-wind, this will often drive the integration of remote generation centres and the demand for massive radial network expansions on the green field. But if regulatory frameworks fail to account for, allocate and moderate between network investment-related system-wide costs and benefits over time, the outcome will either be uneconomic transmission capacity shortages or excess capacity resulting in low utilisation factors. Furthermore, without a sufficient cost-benefit allocation or cost socialisation, new investment projects will remain challenged by those market participants carrying costs without receiving commensurate benefits. And finally, if infrastructure needs in quantity and timing cannot be justified for every single project, in areas with dense population or lacking environmental protection then public opposition, investment delays and reduced system economics will be the rule rather than the exception.

Figure 14 • Efficient market structures and regulatory frameworks for network investments



Any regulatory framework around new transmission investments should aim at the holistic inclusion of all these aspects and stakeholders across the market as this can significantly contribute to maintaining reliability whilst enhancing electricity system economics and acceptance for new investments. Network infrastructure planning frameworks can play a significant role in co-ordinating all these aspects and stakeholders. Provided coordination between independent planning entities exists, such frameworks can find best solutions and ensure widespread acceptance. Cost-benefit assessments and accurate cost allocation will play an important role in determining these best solutions. Frameworks allowing for a high level of market-based solution finding enable the establishment of planning interfaces to adjacent systems, which develop both network structures on the greenfield in remote locations and merchant investments (Figure 14). Electricity flows follow physical rules and thus can easily cross “virtual borders” of network planning. Therefore it’s beneficial if network-planning frameworks acknowledge the existence of such flows and seek the best technical solutions in a representative area. In cases of developing remote greenfield connections of large-scale generation centres, such planning interfaces will even be necessary to arrive at co-ordinated network infrastructure developments.

Key findings • Planning frameworks should coordinate between expectations of various market participants, adjacent systems and policies and should determine beneficiaries and benefits. Missing benefit quantification and allocation can lead to increasing investment cost socialisation and this challenges acceptance.

At the same time locally accurate investment assessments, undertaken in open planning frameworks, can inform all relevant market participants on investment opportunities. Both aspects, cost allocation and open planning accuracy, can also help to minimise, optimise, defer or even avoid investments as they can potentially identify economically justifiable investments in quality, quantity and time.

Actively involving all relevant market participants in the planning and solution finding process can potentially foster the desired investment optimisation. The concept of an holistic planning framework comes close to the Public Contest framework established in the 1990s in Argentina (Box 6) and is also represented in the new planning and cost allocation framework established by FERC’s Order 890 and Order 1000 in 2007 and 2011 (FERC, 2007 and FERC, 2011c). In response to these orders, NYISO has already updated its planning and price-setting standards (NYISO, 2012) and the way new transmission investments will be planned, assessed and their costs allocated. From these planning frameworks, seven fundamental planning principles can be identified:

- Coordination *i.e.* all customers and adjacent transmission owners are bound to actively participate in the planning and solution finding process, including load-serving entities.
- Openness *i.e.* transmission planning must be open to all affected parties.
- Transparency *i.e.* the used planning tools, criteria, assumptions and data underlining the transmission plan have to be open to every planning participant for input assessment and result duplication.
- Information exchange *i.e.* all data, including load development data, have to be exchanged between transmission planners and market participants. Relevant assumptions and planning data have to be consulted with the market prior to utilisation.
- Economic planning studies for congestion alleviation that identify congestion location and magnitude, possible solutions, associated congestion-relieving benefits, costs of relieving congestion.
- Cost allocation for new projects *i.e.* the beneficiary pays.
- Dispute resolution - provided by an independent expert before the regulator intervenes.

Key findings • General network cost allocation can contribute to system-wide cost minimisation between loads/generators and networks. Open planning frameworks with clear planning principles can further optimise investment needs in a competitive manner.

As well as the planning principles mentioned above, several other factors could influence the success of such a planning framework. Transparency and accountability of the planning framework, combined with clear rights, responsibilities, timelines and dispute resolutions are likely to attract all relevant market participants. Strengthening the openness of the planning framework for all potential regulated solutions with tendering identified network investments can identify competitive least-cost solutions in transmission network upgrades or more efficient transmission network management in particular. Early experiences from such tendering regimes in the United Kingdom show promising results with regard to economic efficiencies, with estimated cost savings (Ofgem, 2012a). Tenders can also help limit the incentives of an incumbent network planner/owner to benefit from over-expansion of the transmission network. Allowing for market-based non-network investments, such as energy efficiency, demand side response, storages or distributed generation to compete against regulated, network-based solutions can also reduce cost pressure and ensure the best solutions. Examples from the US electricity regions seem promising as transmission developers were able to significantly reduce network investment costs by including energy efficiency and demand response in their often locally targeted forecasting. Experiences from system operators seem to mirror these benefits where energy efficiency forecasts helped revise the transmission needs' total by an estimated USD 260 million. These benefits are also the reason why FERC recently started to consider non-transmission alternatives during regional transmission planning in organised US electricity regions (FERC, 2011c). However, the non-network investments will also require clear rules provided by planning frameworks so as not to distort efficient planning and solution finding. As such investments will not necessarily benefit from regulatory investment coverage and associated long-term investment security the efficient functioning of the general electricity and ancillary service markets will be necessary to secure their funding. If electricity and ancillary service markets function well in terms of transparency, competitive and undistorted pricing, long-term predictability and local accuracy, this is likely to significantly reduce economic barriers for the uptake of non-network based investments.

Both processes, tenders and non-network investments, should be guided by a clear set of criteria for the evaluation of the project developer to assess the financial and technical capabilities and expertise to develop, construct, own, operate and maintain facilities. Tenders as well as non-network investments combined with financial assessments can alleviate an otherwise potential problem of financial scarcity, which could otherwise significantly delay required investments. Some incumbent network operators, with the sole right of project development in their transmission region, already indicate their interest for such regimes, as they struggle due to missing financial resources and timely delivery (Tennet, 2011 a). Financial resource scarcity can become particularly relevant in cases where initial public offerings, stock market launches or other methodologies to increase the equity base are either too costly, time consuming or even strategically impossible. Disregarding the solution, assessing the delivery timeline from the starting date to the final commissioning of each possible project can help as this identifies earliest availability. This information can enhance the evaluation of the market result of each project: a network infrastructure with a ten-year development timeline cannot yield the earlier economic benefits of faster developed projects, such as demand-response.

Region-wide planning, as opposed to planning in each transmission owners' region, is hugely beneficial. This is particularly true for countries and regions with more than one transmission owner in place. Such region-wide planning, if co-ordinated in terms of data, assumptions, assessment tools, transparency, involvement and cost allocation, can avoid double accounting of

investment drivers and also find best solutions in often highly meshed systems. Meshed systems often offer the possibility of accommodating electricity flows over various routes and this wider-area flow assessment can identify the minimal required investments to reliably accommodate expected power flows.

Box 7 • The UK's new framework for building competitive network infrastructures

Since 2010, Ofgem has provided a legal framework (UK Gov, 2010) to make tender regulations to determine a competitive basis upon which an offshore transmission licence can be granted. The reason for allowing the tendering process to build the offshore network infrastructure for offshore wind farms was to ensure a cost-effective and timely network development. Over a consultation period, Ofgem has established its final statement on the competitive tender process (Ofgem, 2009). The offshore transmission owner (OFTO) is selected through a competitive process and initial analyses by Ofgem's estimates of significant cost reductions to generators and consumers.

The tendering rules allow for the asset development, either by wind farm investors or by independent network developers, which provides flexibility for generators in terms of who constructs the assets. If the generator chooses to build the connection, he has to transfer the assets to an OFTO upon completion of construction. The OFTO will then have upfront clarity over their revenue stream over the 20 years of depreciation, paid by National Grid Electricity Transmission (NGET), the onshore transmission system operator, and there will be no additional revenue regulation. The revenue stream includes all relevant costs for financing, designing/constructing (if applicable), operating, maintaining and decommissioning of the transmission assets. Through network charges, NGET will allocate these costs to all network users.

Results from the tender show success in attracting investors with new entrants and new sources of finance demonstrating interest in the sector with funding of up to almost USD 6.4 billion being offered in relation to the USD 1.75 billion⁴³ of assets in the first tender round (Ofgem, 2012a).

The incorporation of distribution networks into the planning framework can further optimise investments. To date, transmission and distribution networks have been more or less independent from each other. Transmission planners and operators often consider distribution networks as predictable loads with uni-directional power flows from the transmission to the distribution level. However, comparable to transmission networks, distribution networks often also show meshed network infrastructures in underlying voltage areas. With the inclusion of this underlying infrastructure into the best-solution determination for solving network congestion, the existing network infrastructure can be better utilised and required investment needs minimised. This optimisation and minimisation will potentially require the formation of several distribution network operators to knowledgeable planning participants. Littlechild observed the formation of such professional and active planning participants and the investment solutions, with enhanced economics, in the Argentinian electricity market (Littlechild, 2008a, Littlechild, 2008b and Littlechild, 2011).

There can be further benefits of an efficiently established transmission-distribution interface, such as the active participation in wholesale electricity and balancing markets with distributed generation and demand side management, and these are further discussed in the section on distribution networks.

Key findings • Tendering can potentially allow for cost reductions via competition and help overcome financial resource scarcity for undertaking timely investments. Region-wide planning facilitates best solutions and avoids costly double accounting so distribution networks should participate in this planning.

⁴³ At a conversion rate of 1:1.5977.

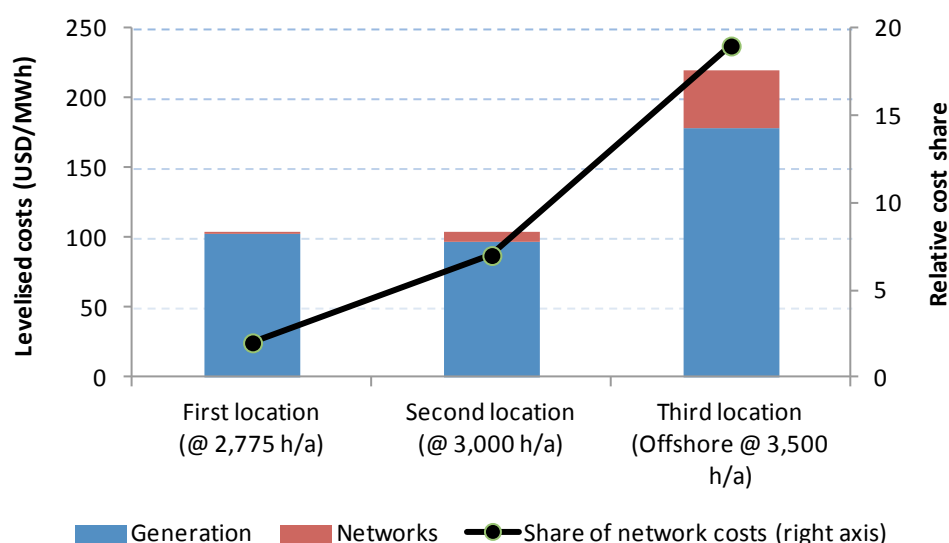
Implementing network costs into locational decision making

Introducing holistic network planning frameworks into electricity systems can provide the best outcomes from a technical, economical, environmental and social perspective. New network investments are often expected because of the integration of power flows and renewables as well as generator relocation and advances in generator technologies. However, network investments are not for free and can form a significant share of total electricity system costs. If generators are allowed to take their locational decisions without being exposed to the associated incremental network costs, their locational decisions can result in higher than required system costs.

Therefore it's beneficial to establish reliable price signals with sufficient local resolution, which indicate the network-related incremental capital costs for connecting and integrating new generators and loads. The allocation of these total incremental network costs to the generators and loads being responsible for incremental network costs (deep charging) can influence generators' choices on where to locate. This can contribute to the minimisation of incremental electricity system costs, including loads, generation and network costs.

There are different outcomes of shallow and deep charging for network investments for the integration of new wind generators (Figure 15).

Figure 15 • Example of system-wide costs with different network cost allocation frameworks



Source: network cost data from AEMO, 2012.

Imagine new wind generation capacities of 1.5 GW to be added to an electricity system at two possible locations. The first location offers better network access and integration conditions in a well-developed network area. With 3 000 hours of full load a year (h/a), the second location offers better wind conditions in a remote location. Assuming equal capital investment requirements for the generation capacities (USD 1 750 /kW), in a shallow charging system the generation investor would choose to locate in the second location. Furthermore, (IEA, 2010) is assuming a 10% discount rate, a 25-year lifetime as well as operation and maintenance costs at USD 30/megawatt hour (MWh), this will lead to electricity generating costs of USD 97/MWh. As a consequence of this locational decision, network upgrades of 200 km will be required to fully integrate the generated electricity. The transmission distance will also require one reactive power compensator as well as several transformer stations for the deep network integration.

Over the same 25-year-lifetime, the level network costs reach USD 7/MWh. Together with the generation costs, the system-wide costs will be USD 104/MWh with a share of roughly 7% coming from required network upgrades. In a shallow charging system, these network costs will be socialised.

The required network upgrades of only 10 km, and an equal number of transformer stations in the first location to fully integrate the wind generation, will cause network costs of roughly USD 2/MWh. The question is at what generation costs system-wide costs will be lower, as in the second location. As these generation costs relate to the wind generation capacity utilisation, the decision where to locate can be linked to the achievable hours of full load. In this example, any achievable utilisation factor above 92% of the maximal achievable 3 000 h/a in the second location would contribute to a system-wide cost minimisation. From these, roughly 2 775 h/a upwards, the generation costs fall below USD 103/MWh and the share of network costs on system-wide costs falls below 2%.

Applying locational decision-making methodologies to all generation technologies can significantly contribute to system-wide cost minimisation. This can become particularly relevant in cases where offshore network structures far from the shore are required. Compared to onshore solutions, offshore wind generators offer the benefits of significantly higher utilisation rates as well as lower opposition levels from an environmental and social perspective. These aspects show that offshore locations can be regarded as a third location option in this example. Despite the better utilisation conditions, offshore wind is significantly more expensive compared to onshore solutions. At investment costs of USD 4 200/kW and a 10% discount rate, achievable h/a at 3 500, a 25-year lifetime as well as USD 40/MWh costs for operations and maintenance, the total costs for generating electricity almost reach USD 180/MWh.

At the same time, a change in network technology from AC to DC can be required, as the maximum power transfer capabilities of AC cables decline fast. Especially for higher voltage AC networks, a 50% transfer capability reduction can already be seen at distances below 100 km (NG, 2009). However, DC technologies such as cables and offshore platforms are more expensive than AC solutions. In addition, expensive converters from DC to AC are required to finally feed into existing electricity systems.

In the example the integration of 1.5 GW offshore wind capacities would require 100 km subsea DC cables. Due to missing options to scale the networks' capacity, the wind integration will further require several offshore DC platforms and onshore DC/AC converters. In this example the DC related network costs rise to roughly USD 30/MWh. System-wide costs reach more than USD 205/MWh in this example, with network costs at a share of almost 15% of total costs. This share can increase even more if network upgrades onshore are required as well. However, due to the reduced scalability of most network parts, the share of network-related costs can remain stable even at higher generation capacity installations. A 20 GW offshore wind generation capacity can lead to higher total system costs but the flat generation and network costs can remain at roughly the same levels. This example shows that system-wide cost minimisation between network and generation costs can be beneficial. This is true for onshore locations where various cost drivers can influence the locational decision. Deep network charging methodologies can contribute to achieving more competitive renewable generation capacity investments. As a result, the system-wide cost minimisation can determine an efficiently determined amount of new network infrastructure. This can become beneficial as acceptance levels can potentially be increased by such methodologies. The methodology is also applicable to other generators such as most conventional plants or solar PV, as either fuel transportation costs or solar irradiation patterns can be influenced by locational decisions.

For achieving such system cost minimisation between loads, generation and networks, network costs need to be allocated to the cost-causing market participants, the generator in this case. This is particularly relevant in cases where significant amounts of new renewable generators seek connection and conventional generators relocate. Ex ante awareness of the location-specific long-run network-related cost effects of changes in generators' and loads' location and/or output and/or demand has to be provided by system operators. Adding network-related long-run cost effects to the original system of short-run locational marginal pricing (as discussed in the section on transmission network operations) is potentially the most accurate and comprehensive framework. Combining the local value of network use with the location-specific cost assessment of potential new infrastructure investments is already under way and supports investment planning on the network level in some regions such as PJM (PJM, 2012d). However, there is so far no system in place that allocates location-specific incremental network costs to renewable generators. This shortcoming is likely to become one driver for causing inefficient system costs and needs further adjustment of currently existing best practice models, which will have to account for the effects of reallocation to various generation technologies.

Key findings • Accurate localised network cost allocation can contribute to minimising total system costs by balancing incremental transmission costs with generation and load costs. This balance will become particularly relevant in decarbonising power systems where new renewable generators connect. Such frameworks for system cost minimisation must be applied for renewable generators.

Accurate cost-benefit assessments and allocation can foster project investments

Network infrastructure developments often yield changes for several market participants. One of the most straightforward forms of such changes is an established connection between two regions with initially different electricity prices. On the generation side, the connection brings benefits to the generators in the low-price region as their product can be sold at a higher price to loads in the higher price region. At the same time, marginal generators from the high price region might dispatch less often and this can reduce their revenues. Provided there is sufficient network capacity, this supply change will lead to the alignment of prices between the regions. On the demand side, winners and losers can be found in the opposite direction after the network connection has been established where customers from the initial high price region benefit from reduced supply costs and the customers from the lower price regions face higher supply costs.

Only if the net benefits of power flows exceed the costs for the new transmission line, can the investment be regarded as economically justifiable. The exact determination of all relevant benefits as well as their methodology for quantification remains to be identified to inform the relevant market participants. There are nine benefits of a direct and economical perspective:

- shared reserves;
- higher reliability and supply security;
- load cost savings;
- enhanced competition;
- production and operational cost savings;
- capacity savings due to reduced network losses or reduced reserve margin requirements;
- recovery of (partly) stranded investments;
- congestion relief;
- environmental cost reductions such as carbon emission reductions.

Direct costs include investment costs for the assets and the social and environmental costs of transmission investments.

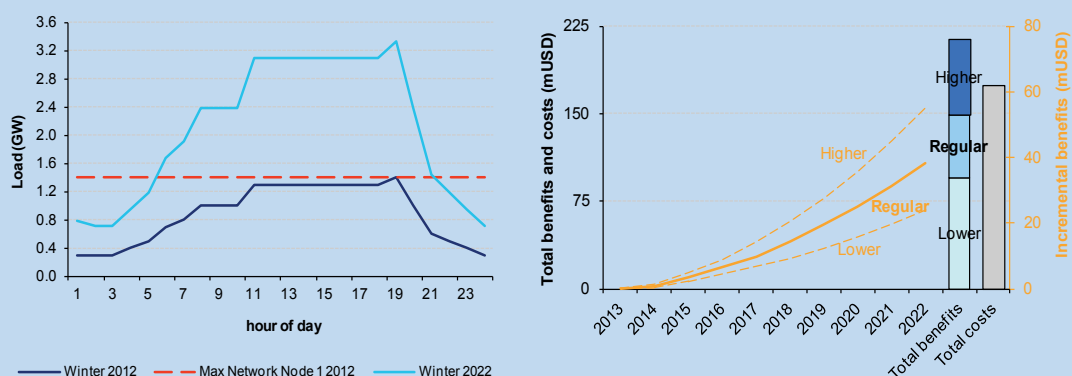
Box 8 • Transmission planning for enhanced economical benefits via congestion alleviation

Transmission network infrastructure bottlenecks can temporarily disconnect loads or parts of loads from supply sources leading to the involuntary load shedding or reduced system economies as more expensive generators get dispatched. Network congestion can also reduce the electricity systems' capabilities for renewable integration, if renewable feed-in exceeds the (temporary) available network capacities.

In general any new network investments aiming at enhanced economics should fulfil the principle of incremental benefits exceeding the incremental costs. Accurate determination of costs and benefits as well as a suitable assessment timeframe and associated risk evaluation are key aspects to be included in each cost-benefit assessment (CBA). In addition network upgrades should always be justified against other general available measures, such as demand response, energy efficiency, storages, levels of distributed generation or by driving the system closer to its limits by creating real-time system state awareness such as by dynamic line ratings (DOE, 2009b). Electricity systems vary with local conditions and the already existing infrastructure, e.g. a highly industrialised region will potentially find a least-cost solution in introducing demand-side response measures for peak shaving during single hours (Figure 16). Under these conditions, openness for all technical solutions should be accompanied with an obligatory CBA for all solutions for the purposes of comparability.

Principles of economic planning and the trade-off between added network infrastructure costs and non-realised market benefits can be generally explained in a simplified example, which shows that sometimes power flow limitations can be more cost efficient than eliminating all network bottlenecks. This general result is in line with assessments from US electricity markets (US DOE, 2009b). Imagine a load with winter peak demand in 2012 at 1.4 GW and this demand to constantly rise until 2022 by 8% per year to 2.8 GW. In 2012, the load was fully supplied through a 1.4 GW transmission line by a generator located at node 1 with supply costs of USD 40/MWh. With the increase in demand above the line capacity, additional supply above the capacity limit can be bought for USD 70/MWh from node 2. The alternative solution would be a network capacity upgrade of USD 175 million to node 1 for maintained supply at USD 40/MWh. Since both options ensure reliable supply, evaluations can be made on the economic assessments comparing the network investment costs with the benefits of a maintained price level during demand situations above the initial transmission capacity to node 1.

Figure 16 • Peak demand as one network investment driver and *ex ante* investment testing



Over a ten-year timeframe under the assumption of a regular 8% annual demand increase, the incremental total benefits add up to USD 149 million, while an assumed 2%-points higher or lower demand growth will lead to benefits of USD 213 million or USD 95 million respectively. Only in the case of a higher than normally assumed demand growth rate the network investment costs of USD 175 million will be exceeded by the received benefits. This represents an already risky investment case, which can be further jeopardised by higher than expected network investment costs. Additional risk factors, discussed in the next section, on the demand and price side in particular can apply and will have to be assessed accordingly.

From a social planner's perspective, only those investments with positive net benefits would be brought forward as they would maximise the system-wide net present value of expected net benefits against the net present value of expected costs. This example already shows that there are two important aspects behind most new network investments:

- Net benefit assessments, comprising both negative and positive benefits, should generally recognise full-scale market developments of new investments.
- Ex ante investment cost allocation commensurate with identified beneficiaries can mitigate re-finance uncertainties and enhance project acceptance.

If the results from the ex ante identification of beneficiaries feed into the investment cost allocation, this reduces the need for cost socialisation and is likely to enhance acceptance. In the example above, cost socialisation would allocate costs to both regions and market participants so that non-benefiting market participants would have to pay an unfair determined share. The necessity of capturing wide-area benefits on transmission systems and the effect of enhanced acceptance via ex ante cost allocation have been acknowledged by academia and FERC, which has led to the implementation of FERC's new cost allocation rule for new transmission investments (Hogan, 2011 and FERC, 2011c).

Key findings • Efficient transmission investments should show net benefits exceeding the costs. Costs should be allocated ex ante and commensurate with the identified beneficiaries.

Assessing costs and benefits of new transmission investments is a significant aspect for network planners and developers, as only a positive benefit-cost ratio should justify investments. Compared with, or even in parallel to, the assessment of investment needs as discussed above, CBAs should be developed together with all market participants and this requires the professionalization of all stakeholder groups, a determined set of rights and responsibilities and a clear timeframe. Additionally only an ex ante CBA can identify the beneficiaries who are supposed to carry the investment costs later on. The inclusion of CBAs into the planning framework can facilitate transparency and consultation among all market players, which will likely result in acceptable assumptions on important factors triggering future costs and benefits. The co-ordinated development of such assumptions on future conditions is essential, as any investment planning should be based upon anticipated developments. However, the level of anticipation should also be accompanied by risk assessments, as already applied by Midwest ISO (MISO, 2011) as uncertainties in the assumptions can lead to varying investment results. Risks can be generally regarded as price risks and/or quantity risks for all relevant assumptions such as demand, fuel sources or supply capacities and their projection into the distant future increases the uncertainties. The influence of different timelines on final investment decisions will often be technically significant and transmission lines will often be capable of catching long-run benefits over the following 40 to 60 years (Box 8). However, applying such a long-term planning time frame will inevitably increase planning uncertainties. As this includes risks of under- or over-estimated benefits and associated investments, adequate measures to assessing long-term benefits and risks for economic planning principles often remain to be developed and implemented into regulatory decision making.

The ex ante cost-benefit calculation must also be specific to local conditions, as any investments will have local influence and as loads and generators can show specific diversities. A zonal assessment approach would only identify zonal costs and benefits, which would result in a zonal cost socialisation. The inclusion of generator and load-specific conditions is relevant as, for example, contract situations for some generators or loads might exclude these market players from benefits of additional investments. The full inclusion of all market players will exceed the information handling capabilities of one single network planner, which demands a voluntary and unmandated participation of beneficiaries as introduced by FERC (FERC, 2011c).

Together with the accurate cost and benefit assessment, the cost allocation remains one of the essential barriers to the facilitation of efficient and acceptable new investments. The developments from organised US electricity market regions are recent and it is too early to assess their investment effects. Therefore the discussion around the regional introduction in planning frameworks, the utilised benefits and cost, the associated uncertainties as well as the resulting investment should be continuously monitored and assessed in terms of acceptance, development time and market benefits.

Key findings • Benefits will increase with the timeframe of evaluation but so will investment risks, which have to be assessed and taken into account. New planning and cost allocation frameworks have emerged globally and their set-ups and results should be carefully evaluated.

Renewables, reliability and their market value

An adequate consideration of investment driving factors and planning principles is necessary for facilitating sufficient and well-timed network investments. The design of planning frameworks will determine new network infrastructures' architecture for the next 40 years and beyond as well as the associated costs, which are likely to constitute between 30% to over 50% of the total electricity systems' investment needs (RMI, 2012). As discussed above, investment-driving factors' benefits should be quantifiable to inform cost-benefit assessments. The allocation of investment costs to the beneficiaries can enhance the cost efficiency of the network-related expenses (Hogan, 2011). If beneficiaries are accurately exposed to the costs they cause, they will vote for transmission investments with maximised economical benefits by matching marginal costs to marginal revenues.

However, network investments for renewable integration are often not justifiable under the current benefit assessment frameworks. This missing justification can undermine investments through hindered regulatory cost approval. Additionally, without a sufficient amount of beneficiaries, new investment projects will be reviewed in the light of the missing acceptance of other market players. The question is if, and when, renewable generation will show sufficient direct quantifiable benefits to pass the existing cost-benefit assessments for enhanced system economics. Under the current capital and operational costs, this is largely influenced by prices attributed to carbon emissions and other pollutants. It can technically also include other more region-specific aspects, such as reduced water consumption or enhanced system resilience from distributed generation.

In the meantime, and during the absence of a clear and sufficient market value for carbon emissions, it is likely that new transmission investments for renewable integration will have to proceed under the application of second-best planning methodologies. Reduced efficiency of network investments will become inevitable as information asymmetry weakens the position of network planners and regulators to identify economical investments. This position will be even more influenced in cases where cost allocation for new network investments is replaced with cost socialisation. Under these circumstances, network costs do not influence investment decisions with regard to generator location and the generators will locate for generator-specific benefit maximisation. As discussed in the section above, the missing cost allocation is likely to result in higher than required network costs. Together with the low or missing quantifiable market benefits of renewable generation, this can be further regarded as discriminatory treatment of existing and new to-be-connected conventional generators or other abatement measures providing for the same product at a cheaper price.

Box 9 • The market value of renewable electricity sources for a network planner

So far electricity generated from renewable sources is remunerated by schemes outside the existing competitive electricity market. Competitive electricity markets remunerate the costs of dispatched power plants based upon the marginal costs of the dispatched generator required to meet electricity demand. At the same time, the uptake of renewable electricity is driven either by the remuneration outside the competitive electricity market through support schemes such as feed-in tariffs, by renewable obligations on a certain amount of renewable electricity in the mix, tax incentives etc.

These forms of remuneration of renewable electricity generation were chosen as prices on the competitive electricity market were not high enough to trigger investments into renewable generation in most locations. One important driver for the political push towards renewable electricity is the reduction of carbon emissions and schemes generally exist to internalise the external costs of CO₂ emissions via trading or tax regimes. However, schemes so far fall short or have not yet been implemented to reach a sufficient and long-term reliable carbon price, a price that would increase generation costs for carbon intensive generators such as coal and gas. In the absence of an existing or sufficient price for carbon emissions, electricity market prices remain below required levels to trigger investments into carbon-free electricity generation sources.

If a sufficient carbon price can trigger carbon-free generation, this may be seen as a significant improvement to a fully competitive electricity market, which tends to minimise generation costs. It could further meet the requirements of a least-distortive support scheme. Natural competitiveness of low carbon generation supports network planners in their process of assessing economically viable network investments by performing cost-benefit assessments. Under the circumstances of a competitive electricity market with sufficient carbon price, network planners will find it easy to quantify the competitive benefits of added carbon-free generation. These benefits will be either a generation cost reduction, in mature or more carbon-intensive power markets, or a minimisation of incremental costs for meeting growing electricity demand. These benefits will then be usable by network planners for identifying those network investments, which show a maximal cost-benefit relation with benefits generally exceeding the network investment costs.

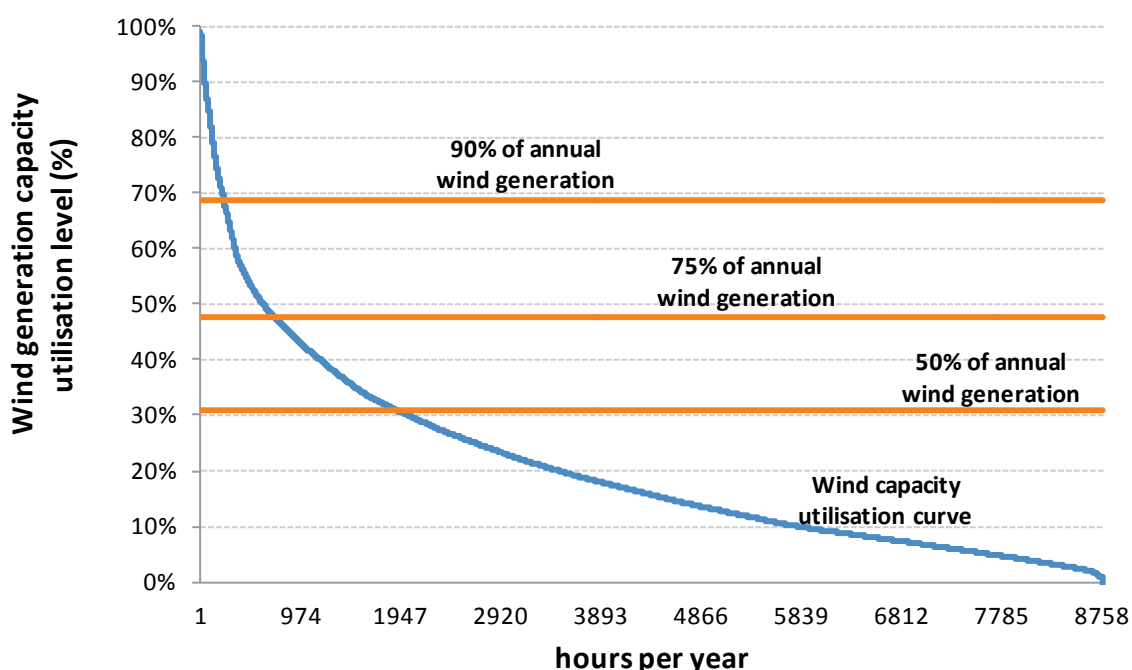
Since carbon prices are either non-existent or low they often fail to support the competitiveness of low carbon electricity against other generation sources. Applied public policy obligations for renewable deployment build upon unquantifiable broad societal benefits of renewable integration. These benefits are used to justify generation and network investments. Since these benefits remain impossible to quantify, the socialisation of network investment costs can result. This can lead to adverse economic and policy impacts. Generators will not face the true network investment costs of their resource decisions and may decide to locate in remote areas that require long-distance transmission. This might be an often more costly approach compared to other decarbonisation options. Furthermore, siting may become more difficult because those required to pay for the transmission lines do not see the benefits and will litigate both the cost and siting-approval processes.

Introducing public policy obligations as planning criteria and cost socialisation to loads for renewables integration very often remains a common integration methodology and a tool, with high connection certainties. Under these schemes, system operators or regulators determine favourable generation zones for a pre-determined maximum amount of renewable capacity installations or renewable electricity generation over a certain time frame. With regard to the location of these zones and the expected generation capacity, the required network infrastructure is planned and the associated costs socialised. Such an administered regime can be seen in several regions in the United States, such as MISO (MISO, 2011) or ERCOT (PUCT, 2013), and also in Ireland, where EirGrid facilitates the developments in so-called group processing approaches (GPA) (CER, 2008 and EirGrid, 2012). Other frameworks provide comparable clarity for facilitating network planning and re-financing to accommodate the integration of large shares of renewables. In the case of Germany, network operators are obliged by law to connect

renewable generators independent from their location to the grid and to expand network capacities to fully accommodate their electricity flows (Bundesministerium der Justiz [BMJ], 2009c).

Some regulatory frameworks oblige network developers to design renewable generator connections and to mitigate system-wide network congestion for 100% renewable electricity network integration as well as to compensate (without refund) renewable generators for any foregone revenues of reduced integration. Whilst this gives additional investment certainty to renewable generators this approach is likely to lead to further uneconomic network investment decisions and thus can create excess costs to the electricity system and its users. An unbalanced electricity system development plan with network overcapacity can also lead to increasing levels of opposition. These excess costs can be seen as a result of missing benefits of cost allocation to the beneficiaries, where only projects with positive benefit-cost ratios would be pursued by active generation-seeking market participants. The network infrastructure investment results of a 100% feed-in full compensation, based upon Germany's annual onshore wind generation pattern⁴⁴ with roughly 25% average generation capacity utilisation (hours of full load). The annual generation capacity utilisation curve (wind duration curve) of the total installed wind generation capacity is of interest (Figure 17). There is a steep decline until the hour 500, which implies that capacity utilisation shares above 50% happen in less than 500 hours per year. During these 500 hours, overall wind generation was at 22.5%. Nevertheless, this steep ramp down also implies that the 220 hours with the highest capacity utilisation share only contributed to 10% of the overall annual wind generation. In view of this, the question of efficient network infrastructure investments determined by cost-benefit assessments is even more important.

Figure 17 • Annual wind generation capacity utilisation curve (wind duration curve)



Source: wind generation data from German transmission system operators.

⁴⁴ based upon 2010 feed-in values and installed wind generation capacity.

Accommodating 100% of wind (“the last kWh”) would require a 30% higher transmission network capacity so as to accommodate 90% of annual wind generation. It’s beneficial, from a system-wide cost perspective, to find a balance between incremental benefits of renewable integration and network costs (Box 9). Depending on the incremental network costs, as well as the incremental and expected benefits from adding the last kWh of carbon-free wind generation into an electricity system, the efficient network infrastructure investments and associated shares of rejected wind could be determined for each electricity system.

In addition to these potential system-wide investment optimisations, reliability standards for transmission connection of renewables could yield additional cost efficiencies, especially in situations where network operators are obliged to fully compensate renewable generators for any foregone revenues due to transmission line failures. Under such conditions, and in the absence of cost-benefit assessments, networks will often be planned with n-1 certainty for the integration of renewable generation. This implies that even if one transmission line trips, the remaining network capacities are sufficient to fully accommodate renewable generation with full capacity utilisation. As shown above, full capacity utilisation transmission line failures are rare. In Germany’s transmission network, these were identified at 0.4 years per 100 km and 3 hours average downtime per event. This accumulates to average line failure time of 1.2 hours per 100 km per year (Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (BMU)) 2007). If the costs for the additional n-1 transmission line are assumed at USD 170 million for 100 km to integrate 1 GW of wind, the required benefits of wind generation would be required to be at over USD 3 500/MWh to justify the n-1 investment. And this is only in the case of 40 years’ transmission line depreciation and comparable line failures every year.

Key findings • In the absence of a sufficient carbon price renewable generation has a low market value. Second-best approaches based upon public-policy obligations, which can cause overcapacities, reduce economies and increase the shares of costs to be socialised. Reliability principles for generation integration should be carefully assessed on a case-by-case level.

Comparable to overly expensive n-1 generator connection, current principles for reliability planning⁴⁵ can also deliver excess transmission capacity. Reliability-based network planning has been in place since transmission networks developed and has ensured that network infrastructures can always accommodate all electricity demands, even during peak demand decades. In the absence of clear economic value for supplying all loads, reliability levels are generally set by a governmental authority with acceptable failures at “one day in ten years”. With regard to this one-in-ten reliability planning principle, one researcher (Joskow, 2006) quotes an implied value of lost load at USD 267 000/MWh required to economically justify these applied reliability criteria. This shows that the adoption of customer-value oriented reliability benefits can avoid excessive network reliability investments. However, this also implies an assessment of customer-specific willingness to pay for reliability aspects is currently out of reach due to the swathes of different customers who are unaware of their willingness to pay for marginal electricity reliability. Additionally, a load-specific reliability margin would also portray each customers’ ability to manage power flows at their network interface and this would imply the availability of demand-response steering devices at each single load.

Until progress in these two aspects has been made, and research is continuing (US DOE, 2009), a reasonable approximation can be to identify the marginal willingness to pay values at single system nodes and apply these values for cost-benefit assessments to reliability-based new network investments on this node.

⁴⁵ Principles for reliability planning generally include pre-determined targets for sufficient supply infrastructure. A “1-in-10” planning principle would require infrastructure planners to only lose supply for one day if demand conditions are driven by exceptional circumstances only likely to happen every 10 years.

A further improvement of the currently applied n-1 reliability planning principle seems to add probabilities to the deterministic principle. Deterministic approaches, without assessing the impact of one specific system component, miss the opportunity to give each component a specific relevance. Measuring the specific relevance in terms of fault probability and fault impact to the system can contribute determining components with a required n-1 security. Applying probabilistic n-1 principles in system operations, as discussed in certain research (IEA, 2005) can reduce overall system costs through less capacity installations and back-up systems whilst maintaining system security at the same time.

Key findings • Current reliability obligations can often exceed the customers' willingness to pay for reliability. These obligations can lead to network overcapacities and increasing network costs needing to be socialised. Until all customers' willingness to pay can be fully assessed, assessing the willingness of important customers to pay can potentially help reduce overinvestment.

Connecting bulky renewable generators in remote locations

So far renewable generators have often been connected in smaller capacity groups to the existing transmission network. Usually these radial connections happened close to a meshed transmission network and connection processes exist to avoid connection delays. Germany, where connection queues of renewable generators are minimal, is exemplary as an effective connection framework. The German law on renewable energies (Erneuerbare-Energien-Gesetz (EEG), 2011) constitutes the fundamental connection process, obliging the transmission network developers to establish the shortest and least-cost grid connection on behalf of the generator. The connection has to be established immediately and cannot be delayed by potentially required wider area works to reinforce deeper transmission network structures.

The logic of this "connect first - reinforce later" approach has also become an important principle behind DECC's rulemaking for an "Enduring Regime for Grid Access" in 2010 (DECC, 2010). This approach was chosen as connecting to the transmission network has been identified as a major barrier to generators, including renewables. With regard to the new process National Grid Electricity Transmission (NGET), the independent owner and operator for the transmission system of England and Wales estimated acceleration for average connection times by three to five years (Ofgem, 2011a). Under these new arrangements, only clearly pre-defined enabling works that are required to maintain reliable system operations can delay the connection process. This new process eliminates connection queues through connection requests being put on hold by the network operator until required wider-area transmission network reinforcements are operational. However, this new approach is likely to lead to increasing congestion levels within the network, which will be efficiently solved by new network investments as discussed above.

Regular connections are often paid by the connection-seeking generator, which provides incentives for least-cost connection. Since investments for regular connections are often below 1% of a generator's total investment costs,⁴⁶ these are marginal because the economic burden is quite low. However, with the planned introduction of remote-distanced large-scale renewable generation centres, such as offshore wind parks, the connection costs can reach up to 20% of the generators' capital expenditures (CAPEX), especially when new technologies are required. With progressing electricity sector decarbonisation plans, a variety of IEA Member Countries such as Denmark, Germany, the United Kingdom and the United States are aiming for the connection of large-scale offshore wind farms.

⁴⁶ This calculation is based upon lifetime costs for a 3 km 400 kilovolt (kV) AC overhead line, suited to the capacity of a 300 MW power plant. Transmission costs were taken from (Parsons Brinckerhoff, 2012). The chosen power plant represents an open cycle gas turbine (OCGT) built in the US market. Power plant costs were taken from research (IEA, 2010) and represent overnight costs only.

Compared to onshore solutions with lower distances to loads, this will often create more considerable demands for new transmission network infrastructure. As discussed above, the network costs of such remotely distanced solutions can be significantly high compared to the overall generation technology costs. Offshore wind farms are often located in remote areas and far off the coast to minimise visual impact so that their connection to the transmission grid often requires the development of long transmission infrastructures on the green field. In some cases, wind farms already under construction are 100 km from the shore alone (European Wind Energy Association (EWEA), 2011). At these distances, conventional AC cable technology will have already reached its economical and technical limits, since the amount of reactive power they produce increases over distance, necessitating the deployment of DC cables. Both distance and technology drive total connection costs constitute the generator project's total investment costs.

Allocating the connection costs to the generators can nevertheless help ensure connection cost minimisation, as generators are best placed for influencing their connection costs by their locational choice. Generators will in most cases still be able to decide upon their location since very few generators are really fully location-constrained. Any cost socialisation of these connection costs is likely to lead to economically inefficient network investments and it also conceals the total costs of new, to-be-established generation centres, which can blur efficient choices for decarbonisation. However, this methodology of cost allocation will, under the current circumstances, have to be recognised by public support mechanisms.

Key findings • Costs for connecting remotely distanced renewable generators can reach significant shares of total investment costs for generators. Nevertheless, connection cost allocation should also follow the rule of beneficiaries paying to foster least-cost solutions.

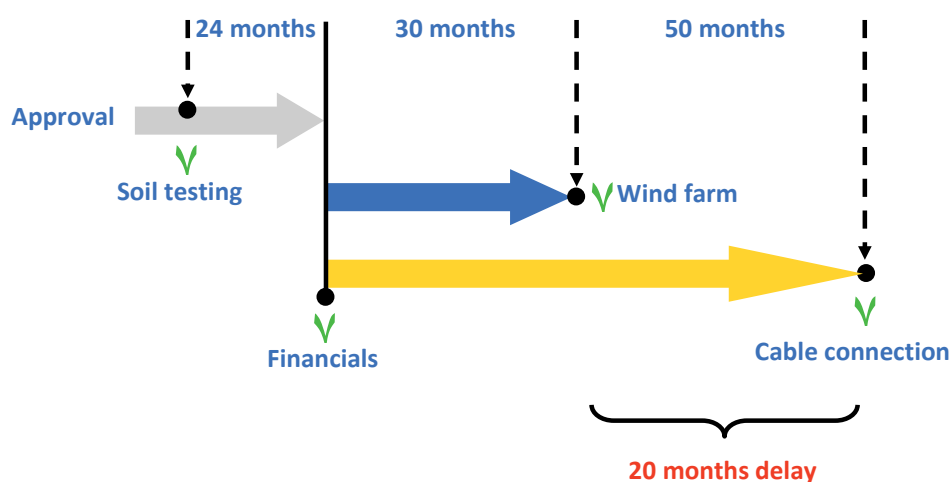
With the notion of unbundling, generators are prohibited to build and operate networks and this also applies for network connections. Therefore network planners and developers have to ensure timely and accurate connection capacity for the remote connections. However, this interface between network and generators can be prone to time-related mismatches and associated delayed or cancelled infrastructure investments. Independent of the connection cost allocation, the connection costs are recovered through the network tariffs. Therefore, the network operator becomes liable for the cost-efficient connection through the pressure of economic regulation and cost recovery. The network operator needs to know when, and by whom, re-payments will be made. Any network underutilisation at the beginning of the investment projects' recovery time can significantly reduce the net present value. This risk is magnified by the network operators' uncertainty about the long-term utilisation question: "will there be any wind farms at all?"; a question arising in cases where regulations prohibit cost socialisation but challenge investments with cost benchmarks in the long run.

Under these circumstances, the network operator will seek to minimise his risk by demanding the offshore wind farm investor to prove that the investments will take place. This security can naturally be the final investment decision or the construction start of the farm. This level of risk avoidance, however, has the potential to significantly delay the connection process once the farm is established and leads to a loss in generated renewable electricity. Timelines for the installation of offshore wind farms, for example, differ from the network connection time (Figure 18). Installing the subsea cable requires studies and consultations on environmental aspects, the establishment of a potential route outside problematic areas⁴⁷ and the final siting approval. Once approved, the cables have to be ordered and manufactured. Cable-laying vessels have to be contracted in most cases and loaded, and often the cable has to be buried in the ground with ploughs to prevent damages by third parties, such as anchors. Wildlife habitats,

⁴⁷ Such areas can be existing pipelines, fishing activity, military activity, ammunition dumps, water depth, seabed conditions etc.

weather conditions and tourist activity can additionally limit the installation time throughout the year. Installing the offshore wind farm also involves studies and consultations on environmental aspects for more or less the same reasons mentioned above. Again, wildlife habitats, weather conditions and tourism activity can limit the installation time throughout the year. However, the manufacturing and delivery process of offshore windmills can be less time consuming in comparison to cable manufacturing and delivery.

Figure 18 • Timelines for the commissioning of offshore wind farms and network connections

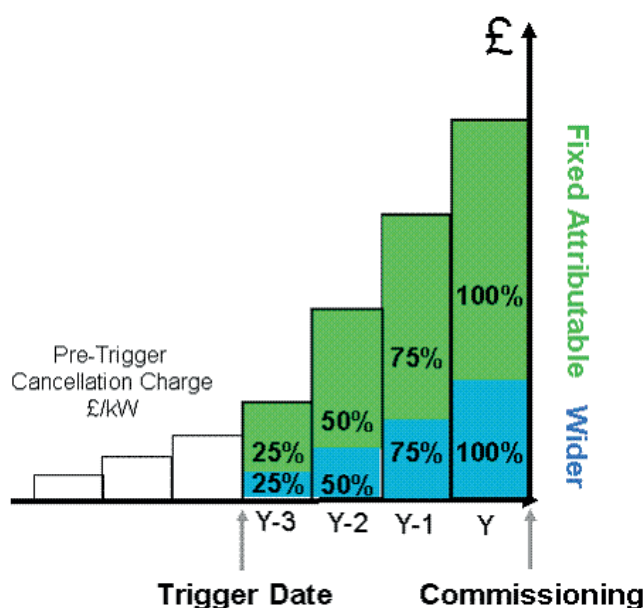


Under the current market circumstances, especially the manufacturing capacities of the two infrastructure pieces, the commissioning of the wind farm can take 30 months ((Energie Baden-Württemberg (EnBW), 2011) from the day of the final investment decision, whilst it can take 50 months to plan, order and install the subsea cable (SIEMENS, 2012 and Stiftung Offshore Windenergie, 2012).

Key findings • Connections often have to be established by network developers who are seeking to minimise their investment risks against uncertain generator developments. A risk-balance between generators and network developers has to be established.

Properly designed regulatory frameworks can help solve this “chicken and egg” problem of misaligned construction timelines in several ways. In certain cases, single farms can be connected with radial connections, which is a preferable model for user commitments. These user commitments, paid by the generator, but recovered once connected, can provide investment security to the network developer without creating an entry barrier to smaller investors. Such commitments can be provided, either project-specific or -unspecific, by letter of credit, parent-company guarantee or cash payment held in escrow (and refundable at the point of connection). The commitments for connection require clear timelines and penalties for delay and a clear definition of which works fall under connection works and which do not. A comparable model is currently applied by NGET in the UK electricity market where commitments associated to relevant works have to be made by each connection-seeking generator (Figure 19). Since former arrangements were a barrier to entry, especially for smaller players, new arrangements have been implemented by NGET and Ofgem (NGET, 2012). Under these arrangements, connection costs of the nearest located connection point are to be fully borne by the generator but can be reduced by a factor for taking potential network re-use into account if connection fails on the generator side. The commitments are phased in annually over four years, increasing towards the connection delivery date with each trigger point (pre-consent, post-consent, commissioning) representing the increasing expenses on the network side. The commitment is reduced to zero post commissioning.

Figure 19 • Phased generator commitments and trigger dates for UK's network connection process



Source: NGET, 2012.

Excluding the option of using anticipated network investments, other models to solve the chicken and egg problem will require higher regulatory coordination between the involved stakeholders, seeking agreements on a single-project base. In the interplay of regulatory risk and generators' risk, the timelines of the two infrastructure pieces have to be assessed in detail to identify an acceptable network investment risk from the regulatory perspective, which can still ensure a timely connection. Regulators have to continuously monitor the development of the process with all stakeholders to determine responsibilities in case of process delays. This can pose a significant challenge to the regulatory entity, especially with non-regulated entities where usually no direct rights over information requests exist. In the early stages especially, this process involves learning on the part of all involved stakeholders and may, due to changing project timelines by or delays, be subject to amendments in each case.

Key findings • Radial connections can potentially be best handled by continuously increasing risk exposure of generators seeking connection. However, since experience with long-distance generator connections is limited, further assessments and international best-practice exchange can provide for additional benefits.

As mentioned above, radial connection models can be successful in establishing single connections between remote distanced generation centres and the transmission grid. With increasing transmission distances but also with an increasing amount and capacities of generators to be established over time, radial connections might be uneconomic compared to meshed connections and this demands for co-ordinated, forward-looking (anticipatory) planning approaches with associated risk assessments. Those planning frameworks may look comparable to the frameworks being discussed for "regular" network investments within the existing network. One body (NYISO, 2011) has already integrated rules for clustering connection requests in its regular forward-looking planning framework, which aligns regular planning frameworks with the planning framework for remote renewable generators. This planning process can help achieving network structures with highest economic efficiency and can also avoid the chicken and egg problem. Integrating such offshore and onshore planning in a holistic approach can additionally contribute to reaching full economic efficiency for new network investments. Their co-ordinated planning can determine the most suitable onshore/offshore connection interfaces

at least cost whilst maintaining system security. Depending on the location, it can also be possible that offshore networks develop and relieve the existing onshore networks from parts of their onshore congestion.

Box 10 • Connecting bulk renewables from the Greenfield: UK going offshore

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The UK Government has set ambitious targets for the deployment of renewable energy over the next decade and offshore wind power is envisaged to play a decisive part. There are indications for 18 GW offshore wind by 2020 and a high potential for possible 40 GW until 2030 (DECC, 2011a).

In 2009 Ofgem and DECC started to look into the regulatory regime for developing efficient offshore electricity transmission networks and in early 2011, Ofgem and DECC jointly launched the Offshore Transmission Coordination Project (Ofgem, 2011b). Under this project three stakeholder fora were held over the course of 2011 to include all relevant stakeholders and their expertise to identifying barriers to coordination/anticipation, assets deliveries and regulatory options. These fora were supported by two expert reports assessing the benefits of anticipated offshore network development (TNEI/PPA, 2011) and the required commercial and regulatory drivers for best achievement (Redpoint Energy, 2011).

In a subsequent report (Ofgem, 2012a) Ofgem and DECC summarised the results of the project, addressed the main barriers and opened a formal consultation on potential measures to support efficient network coordination (Ofgem, 2012b) which closed by mid April 2012. Even with the final decision not being taken yet, the discussions around coordinated and anticipated network infrastructure development already shows expert views on potential benefits and general ideas on how to integrate such investments into the pre-existing regulatory environment.

The expert reports show that a coordinated approach to developing the offshore transmission network could result in an 8-15% cost reduction when compared to using single, standalone connections to shore (known as a 'radial approach'). Another important discovery is that technology progress in terms of subsea cable capacity (limited to 1 GW at the moment) significantly drives cost savings. Coordinated development can also enhance system security whilst in some cases of low wind farm capacity the radial connection remains the most beneficial option.

Criteria without quantification but worth to be further assessed are the negative effects to siting procedures and the timing of generation projects.

Generally, DECC and Ofgem recognise the potential benefits that the coordinated development of offshore electricity transmission infrastructure can offer. However, the report also identifies six main barriers towards the realisation of benefits from coordination and anticipation. These barriers to be overcome include: planning an efficient network (linkage to onshore planning), the approach to anticipatory investment (uncertainties over funding), consenting (too early to site), risk-reward profile for coordinated investments (full cost liability of single generators), regulatory boundaries (interface between on- and offshore network) and the technology and supply chain (interoperability and manufacturing capacity).

Following the identified barriers towards coordinated and anticipated network development, Ofgem has recently started a consultation on proposed solutions to two barriers (efficient planning and anticipatory investments) while reaffirming the request for government- and industry-led solutions for others. It remains to be seen how the associated investment risks will be dealt with against the backdrop of an increasing potential for more efficient network structures.

Key findings • Anticipatory investments for remote connections can bring benefits in the form of cost savings. However, risks of stranded investments will increase, which demand the determination of adequate benefit-risk assessments. Again, since experience with such connections is limited, further assessments and international best-practice exchange can provide for additional benefits.

Meshed offshore networks, developed in an anticipatory manner, can pose an insurmountable barrier to first-mover generators seeking connection on the greenfield. The beneficiary-pays principle, applied for ensuring least-cost development, should not require single generators covering the incremental costs of a meshed and anticipated system. This situation will evolve in cases where the anticipated level of future generator capacities is not reached. Meshed and anticipated networks therefore should take only individual cost-responsibilities into account by designing the charging principles for network connections in such a way that single wind farms commit only to their network connection costs. Residual costs will have to be socialised until totally expected generation capacity has developed. Risks of stranded investments should be carefully assessed on a case-by-case base to balance these risks with the benefits from anticipatory investments.

Applying this principle to anticipated and meshed connection costs can maintain the pressure of generator's cost-responsibility whilst allowing for anticipatory investments. Anticipatory developed networks can also contribute to mitigating commitments for entrants to an already existing connection and thus reducing any potentially remaining entry barriers. In case of entry to an existing line, connection costs should be allocated to the new generator accordingly.

The United Kingdom is expecting cost savings of up to 15% for connecting several of their offshore wind farms in such a co-ordinated and anticipatory approach, embedded into a tendering procedure (TNEI/PPA, 2011 and Box 7).

Embedded siting can speed up approval processes and enhance public acceptance

Deciding on the land-use and siting transmission network infrastructure are two of the last requirements before construction of the network infrastructure can start and this process is prone to significant delays in many IEA countries.

Land-use planning for transmission lines aims to identify the most suitable corridor, usually of 500 metres (m) to 1000 m in width, in which a transmission line can be built. Since transmission lines can be very long, these lines are likely to cross several regions and each region will have a land-use plan. Each plan, set up by local authorities, defines the actual and envisaged use of the land and in some cases includes conservation areas. The Canadian Institute of Planners (CIP) defines land-use planning as *"the scientific, aesthetic, and orderly disposition of land, resources, facilities and services with a view to securing the physical, economic and social efficiency, health and well-being of urban and rural communities"* (CIP, 2012). New transmission lines will have to satisfy each regional plan by obtaining land-use approval, which can be a challenging task, especially in densely populated regions or regions with conservation areas or other protected sites.

Awareness of regional plans, and flexibility to openly discuss the plan for a new transmission corridor can help network planners to arrive at the most suitable corridor for their project. Flexibility in this regard can include corridor-flexibility within the envisaged region, to change the region or to use another transmission technology.⁴⁸ The utilisation of existing planning and assessment tools, such as strategic environmental assessments and environmental impact assessments remains a requirement. However, these tools should be utilised in an open debate, involving all relevant market participants to support the decision for one corridor. The early involvement of local participants and local experts helps to identify the corridor with the highest potential acceptance at the interplay between economic, environmental impacts and suitable

⁴⁸ One classical example is the discussion whether a cable instead of an overhead line would lead to the required level of acceptance.

mitigation or compensation measures to these impacts. Impacts can affect the natural beauty, biodiversity, geological conservation, noise, vibration and even security as well as the social impacts of a project. Beyond upgrading existing network infrastructure, a techno-economical choice should be a preferable result from a holistic infrastructure-planning framework and there are measures that can minimise environmental impacts from new transmission lines. These measures are, for example, undergrounding or the better integration of the new transmission lines into the landscape via suitable corridor management. Nevertheless, the better harmonisation between network developers and environmental groups will often require a far better integration and communication as well as technological improvement to arrive at cost-efficient and environmentally sound projects. First steps in this direction can, for example, be seen with the European Grid Declaration on Electricity Network Development and Nature Conservation in Europe (RGI, 2011) and the European Grid Declaration on Transparency and Public Participation (RGI, 2012a). These guidelines and principles are developed under the umbrella of the Renewables-Grid-Initiative and signed by a multitude of European Network developers and non-governmental organisation (NGO) in the environmental business.

Network developers must realise that new transmission lines will often be challenged by local authorities or other groups and this is often related to the reason for the foundation of the transmission line. Additionally, relevant assessment criteria for land-use are not standardised throughout all regions and mostly not available ex ante the application process. This fragmentation, missing upfront clarity and lacking transparency, often causes (un) expected project delays.

Determining the need is a question needing to be answered in the technical network planning process. During the siting process, this question is likely to arise again, normally when the transparency and involvement of an open planning framework as discussed above becomes beneficial. Again, an open consultation with clear rights and responsibilities and the flexibility to adjust initial propositions to local specifications can contribute to enhanced acceptance. Again, delays are often the case and these are often known as NIMBY⁴⁹ or BANANA⁵⁰ problems of the projects. The acceptance issue and how to overcome, or at least minimise, this barrier for new investment projects has been subject to significant research (Sander, A., 2011).

Key findings • Siting processes should determine and try to minimise all relevant environmental and social impacts by making use of local knowledge through obligatory early communication processes between all stakeholders. Discussing each project's requirements is a necessity in the siting process and an open and transparent discussion should take place during the infrastructure-planning phase. Consultative planning frameworks merged with the siting processes can thus create a high level of consistency, transparency and interactivity.

A sufficient siting framework for new build, upgraded or restructured transmission lines should adhere to six conditions:

- ensure the targets of customer protection whilst maintaining electricity supply affordable and secure;
- ensure public acceptance of required additional infrastructures and changes up to come;
- minimise effects of the new infrastructure to the population;
- ensure environmental protection;
- ensure a transparent and reliable framework for project developers;
- ensure infrastructure deployment in a timely manner.

⁴⁹ Not In My BackYard.

⁵⁰ Build Absolutely Nothing Anywhere Near Anyone.

Fulfilling all these aspects will require a coordinated and holistic framework that streamlines responsibilities between authorities and defines upfront information and consultation requirements whilst maximising the openness and transparency of the process from the outset.

Reliable and transparent rules for land-use and siting approval for electricity network infrastructures can help in facilitating an open and streamlined process with enhanced acceptance. Setting the various evaluation steps and evaluation criteria as well as one important responsible authority to evaluate and decide upon each project application can also be of great help in that regard. Involving local authorities under a framework with clear responsibilities can nevertheless ensure that all relevant assessment criteria for determining the environmental effects of the project are taken care of. Having fixed timeframes and ex ante information requirements for all participants including the siting authority can prevent unnecessary project delays. Setting too ambitious time frames, however, can automatically trigger opposition if they don't allow for diligent environmental impact assessments and consultation procedures. Regarding the question of the need for one specific project, linking the results of infrastructure planning to this first evaluation step can provide an integrated approach towards network infrastructure development. In this regard, it's even more essential in having an open and flexible debate on establishing the network development plan, involving all relevant stakeholders from the outset.

Since the land-use and siting processes will determine the real costs of each project, having a transparent process with integrated information flows to the regulatory authority responsible for cost approval can avoid uncertainties for the network developer. Measures for mitigating environmental impacts are likely to be more expensive and stable and transparent criteria as to the acceptability of these additional costs and by whom they should be carried can be helpful. In this regard, German law (EnLAG, 2011) provides the opportunity for undergrounding certain projects if they fulfil predetermined criteria, such as when these projects cross inhabited zones.⁵¹ In such cases, the incremental costs will be approved and spread over the regulatory asset bases of all German TSOs, and thus will be socialised nationally over all network users. The regulatory framework in the United Kingdom allows for a more situation specific debate, where the network operators will have to find the balance between the incremental costs of project delays and those of undergrounding.

Once the final planning approval has been issued, it would be helpful if this decision under the inclusion of all relevant majority and minority comments is contestable only in front of a limited number of law courts. This can again contribute to shorten the timeline for network planners.

Focussing the responsibilities of need approval, strategic environmental assessment, environmental impact assessment and land-use planning approval within one authority can potentially contribute to a streamlined process, minimising points of contacts and shared responsibilities whilst maximising the density of available and required information. Additionally, it will help to monitor the development progress of specific projects in detail so that the responsible authority can implement measures to overcome development barriers, which might appear during the process.

⁵¹ So far, this applies to four transmission corridors identified as pilot project regions.

Box 11 • Infrastructure siting regime in Germany: full transparency and early consultation

Germany is currently re-shaping its electricity system as part of their future target model towards a more sustainable energy system (the “Energiewende”). The decarbonisation of the electricity system is one of the major factors within the “Energiewende” and the transmission networks will be one significant that will enable this target model’s success. In general, transmission networks will have to be upgraded and new lines will have to be built, especially to accommodate longer transportation distances. These longer distances will inevitably occur with the plan for developing new large generation zones with offshore wind farms in the North Sea and the Baltic Sea. In addition to this, a great deal of new thermal power plants seek to locate close to the North Sea to optimise their generation costs, which largely depend upon their fuel costs. Out of the 13 GW generation capacities under construction or close to commissioning, 38% are located in the north or east of Germany. If they succeed, 46% of the planned projects of 28.5 GW will be located in Northern Germany, with a significant share of offshore wind parks (Dow Jones, 2012). This new generation capacity is envisaged to compensate for the decline of existing generation assets, some of them nuclear, located closer to demand centres.

Since Germany’s demand centres are located in the Midwest and the South, where the largest parts of generation were built before liberalisation and decarbonisation, the existing transmission network infrastructure requires massive upgrades to accommodate these new electricity flow patterns. According to particular research (Netzentwicklungsplan (NEP), 2012b), the existing transmission network, comprising of roughly 35 000 km will have to be adapted with 5 700 km of upgrades in existing AC lines, 2 700 km in new AC lines and 2 100 in new DC lines. These upgrades will be required by 2022 to accommodate the anticipated electricity flows. Several of these projects are already in the siting process and according to one study (BNetzA, 2011a), a significant amount of projects is already delayed due to missing local acceptance and fragmented responsibilities within the siting process.

Regarding the already identified delays and the significant function of the transmission network, the German government has reformed the need-determination framework (planning), land-use and siting process to enhance acceptance and to streamline approval procedures. To enhance acceptance, the land use and siting approval process will now be directly linked to the planning process for new infrastructures. Early, open, transparent and extensive consultation throughout the whole process is sought to ensure the highest accuracy and acceptance from all sides.

The planning process can be seen as the starting point towards final siting approval. This process has now been opened from the very beginning to the public and relevant market participants. Under the moderation of the regulator Bundesnetzagentur (BNetzA), all relevant scenarios, established by the four German transmission system operators, will be consulted openly and for a determined timeframe. Amendments are possible and envisaged to include the most accurate data on generation and load in terms of timing, size and location. This consultation ends with an approved set of scenarios, which the German TSO will use to determine expected electricity flow patterns and violations of technical and operational standards in the actual transmission network. Finding the right set of technical solutions to tackle violations will follow the determination of “weak spots”. This set of solutions (new transmission lines, upgrades, existing capacity maximisation) will have to be developed in a given time frame and will be published and subject to a second open consultation, again involving the public and all relevant stakeholders. At this stage, the results consist of identified transmission corridors and the required capacity within this corridor to be developed over a certain time frame by at least one of the four responsible network operators.

Once the consultation is closed and necessary amendments are included, the TSO asks the BNetzA for approval of these corridors and the required capacity. So as to approve these results, the BNetzA will perform the environmental scoping (strategic environmental assessment) of the envisaged corridors in order to determine the effects to local nature and public. This scoping will include the consultation of local authorities and public and in this regard the routing of the corridors can be changed to finally determine the most suitable and less intervening corridor and meet the required environmental transmission line criteria..

After these corridors have been approved by the BNetzA, this plan (“Bundesbedarfsplan”) will be handed over to the national parliament for approval with or without further amendments. Depending on the scope of the project the BNetzA will have continuative responsibilities in terms of siting approval if the project is of “priority”. This streamlines further siting approval, a process otherwise fragmented by responsibilities of several local authorities. Such projects also enjoy accelerated juridical treatment in case of necessary court hearings: for such projects the first and the federal administrative court will directly take final decision.

The BNetzA can demand for the launch of the approval process, by demanding the responsible network operator to handing in the relevant application details. During the siting approval the BNetzA will involve the local authorities and the relevant public. Statements can be made and amendments can be demanded for, however, the general need of the project and the corridor are no longer subject to a debate. Siting approval will determine the exact location of the new transmission lines to be built. For these priority projects it is also hoped that no additional environmental test will have to be undertaken as such tests have been already performed during the land-use approval process.

With the final siting approval the responsible network operator(s) have the task to continue with the project. Usually this starts with seeking cost approval by the regulatory authority, which is again the BNetzA. Integrated siting and cost approval in one authority is likely to ensure integrity of the overall process and can minimise approval efforts. For the cost approval especially the findings of the general need in terms of time and capacity, the environmental requirements such as cables instead of lines and the final network structure are of relevance.

Distribution networks

The distribution-level management differs substantially from the transmission-level management today. In short, distribution-level customers' prices for electricity delivery and network use are very often annual charges without any real-time component. Further, operators often lack the capabilities to monitor and manage the electricity flows on their network in real-time. With most conventional generators connected to the transmission networks, transmission network operators manage their dispatch and reliable power flows. From the perspective of transmission network operators, the distribution networks have been mostly passive load centres that channel electricity from the transmission level and distributing the resulting top-down electricity flows to their end customers. For this to happen, the distribution network infrastructure has been built for reliably serving peak demand at all times. However, detailed regulatory oversight on network investments often remains less clear as the handling of multiple individual network developers investment plans can be a timely challenge for responsible regulators. When changing electricity systems, there are three hurdles to the general status of distribution network management:

- the integration of renewables today and electric vehicles in the future;
- the enhancement of customers' market activity;
- the interface between transmission and distribution networks.

This calls for changes in the current mode of planning, operation and pricing distribution networks. These management adaptations, guided by clear regulations, will become necessary to co-ordinate a reliable and affordable power sector decarbonisation. However, related distribution-level aspects seem to remain low on the agenda of regulators and policy makers, which stands in stark contrast to the potential future role of distribution networks and the necessary investment requirements. In OECD countries alone, around 30% of all power sector investment needs until 2035 will be in distribution network investments if we follow the approaches, policies and regulations laid out in the New Policies Scenario of the World Energy Outlook (IEA, 2012a). These investments will cover 75% of all network-related investments, covering transmission and distribution, and would be equal to about 70% of the investment requirements in all renewable generation sources in this particular time frame. Whilst these investment scenarios show the economic importance of distribution networks, distribution-level reliability is equally important. Real-time monitoring and management capabilities of dynamic power flows resulting from distributed variable renewable generators will have to be implemented in relevant local networks. These operational capabilities can maintain network reliability, which can become challenged by various technical issues. Further, from the transmission network operators' perspective, the active distribution power flow management becomes essential as distribution networks turn from passive-load centres into active generators. Comparable to the transmission networks, there will be a trade-off between additional infrastructure investments to overcome certain technical issues and efficient network operations. Under current arrangements there can be a push towards an inefficient distribution network infrastructure, which serves certain hours only and largely remains underutilised for most of the year.

Regulatory frameworks will have to be efficiently designed to handle the numerous and heterogeneous distribution networks, their specific development challenges, and the often location-specific most suitable technologies and operations, so as to solve issues arising. Whilst transmission operations and investments are developing significantly, as described above, there is still a need to identify suitable approaches on the distribution level. However, it seems clear that pricing methodologies on the distribution level have a role to play and will have to be improved to better reflect real-time system conditions. This can comprise efficient prices for

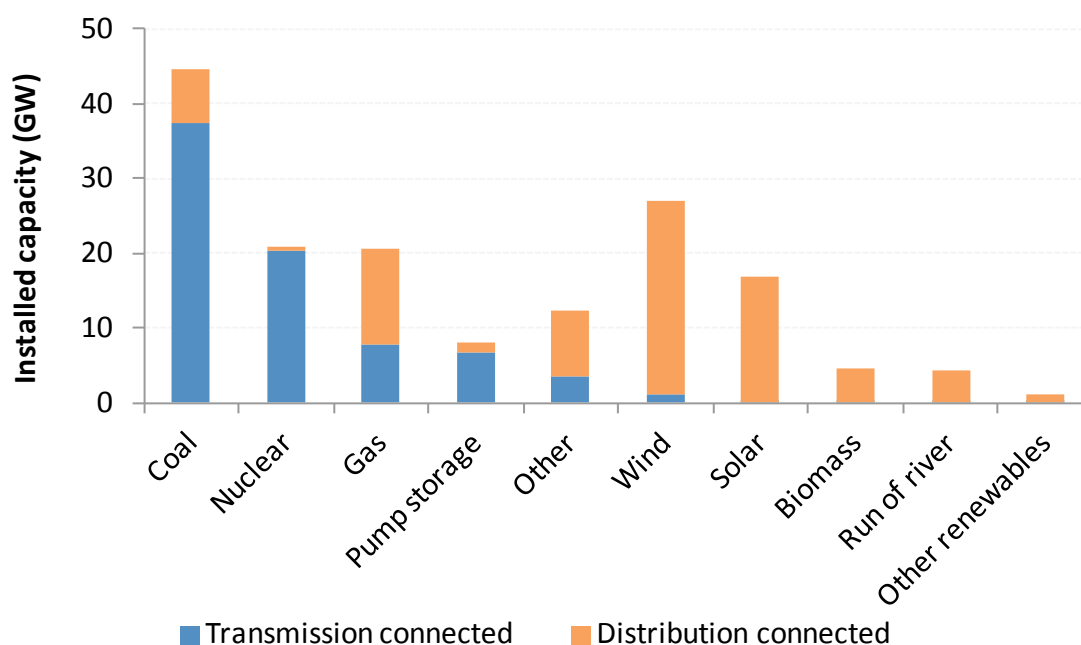
electricity and ancillary services to activate the demand response potential on the distribution level (IEA, 2011b), but maybe also a separate price for network infrastructure use for maximising system-wide net benefits.

Key findings • Renewables, storage, electric vehicles, active demand sources and the interface to the transmission level demand changes in distribution networks. These changes can often be more relevant compared to those on the transmission levels. Co-ordinating these changes to achieve highest economic efficiency requires efficient regulatory approaches, adequate planning frameworks and better operational management. Urgent developments in the distribution networks' regulation and management will be hugely beneficial.

Renewables integration

In some regions, significant shares of renewable generation capacities are already connected to the distribution networks. Some 52% of all generation capacities were already connected to the distribution networks in Germany's electricity sector by the end of 2010 (Figure 20). This amounted to almost 83 GW of generation capacities being connected to the distribution level, where over half of all 48 GW generators are wind, solar PV and biomass plants.

Figure 20 • Generation capacities by grid-level connection in Germany in 2010

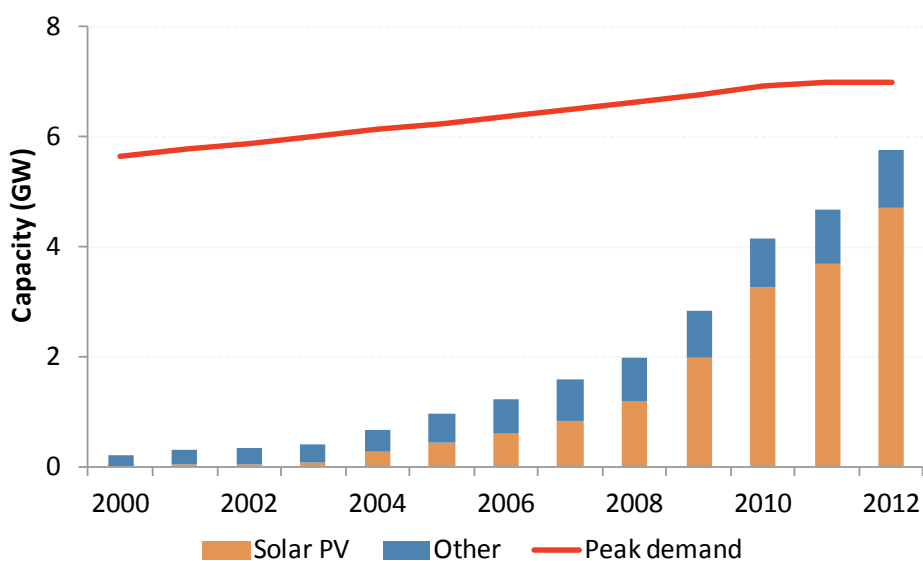


Source: data from BNetzA, 2011a.

The success in Germany can potentially be seen in a legal obligation for connecting any new generator to the network combined with efficient monitoring and dispute resolution management. Additionally, the uptake can also be driven within those distribution companies, which do not own or operate own conventional generation assets as this structure does avoid conflict of interest and discrimination. As long as the significant success factors remain unclear, discriminatory behaviour of vertically-integrated incumbents cannot be fully ruled out, an aspect worthy of further consideration.

Knowledge of the technical implications expands with the larger shares of variable renewable generators bring to distribution networks. A higher demand for best technical and operational solution finding also accompanies this increased knowledge. The uptake of variable renewable generation capacities can be rapid (Figure 21) as in the case of Bavaria, Germany, where solar PV generation capacity has reached over 4.5 GW within a decade. Together with other generation sources, such as wind and biomass, this generation growth has almost reached the peak demand level in this region. There are other regions such as Galicia, Spain, where distributed generation has already exceeded peak demand. The installed capacity of distributed generators in Galicia (2.2 GW) already represents 120% of the area's total peak demand of 1.8 GW (EURELECTRIC, 2013).

Figure 21 • Generation capacity and peak demand development in the distribution network in Bavaria



Source: data from E.ON Bayern, 2012; EURELECTRIC, 2013.

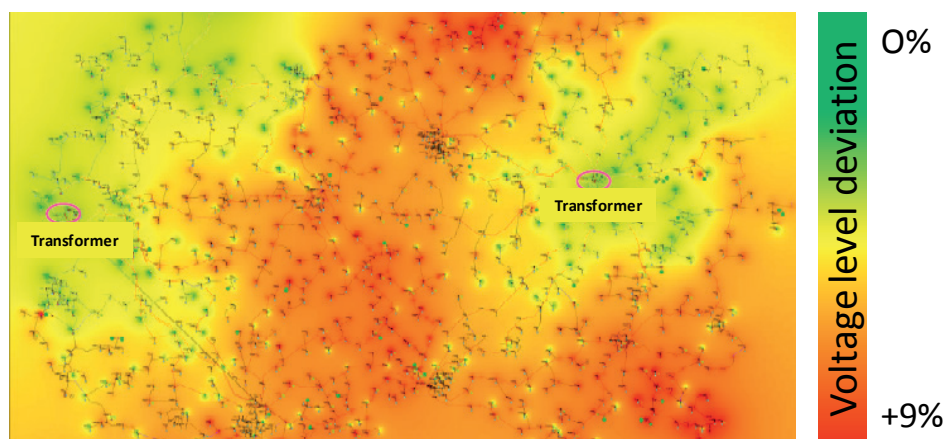
The sometimes rapid uptake of distributed generation can demand fast implementation of efficient distribution network operation and planning frameworks. As a result of past experiences, distribution networks are usually designed for meeting peak demand with power flows coming from, and being organised at, the transmission level. However, with growing distributed renewable deployment situations, local generation is likely to exceed local demand. If not properly addressed, there are four technical problems associated with these situations and the general change of power flows across the local network:

- increasing distribution network asset utilisation and associated lowered reliability reserve margins in parts of the distribution network (n-1 reliability);
- rising levels of distribution network congestion;
- voltage level deviations at distribution level beyond statutory limits;
- overloading of transformers (E.ON Bayern, 2011; EURELECTRIC, 2013; Dena, 2012).

The existence and level of these technical problems will depend upon various location-specific factors, such as the amount of renewable generators; their demanded connection requirements and also the existing network topology and generator location. Some distribution networks are rather widespread and sometimes show almost radial low-voltage connections over relatively long distances, reaching out to almost single loads in rural areas. According to certain studies (E.ON

Bayern, 2011 and Dena, 2012), such rural area networks will be most prone to certain technical problems (Figure 22). In such networks, voltage level increases from technically desired levels in parts of the network can easily appear, especially in those parts being remotely distanced from transformer stations where excess generation cannot be fed back into the overlying voltage level network.

Figure 22 • Local voltage level variations at times of low demand and high solar generation



Source: E.ON Bayern, 2011.

Other issues can arise from unexpected renewable generation variations over seconds where demand for frequency reserves rises. The technical behaviour of wind and also solar PV generators can become more demanding for conventional frequency reserves where the tripping of connected renewable generators can cause a significant loss of generation over short time periods. Such renewable generator failures can be caused by voltage level deviations resulting from various other system failures. Up to certain thresholds, technical generator connection requirements ensure that conventional generators remain connected to the network during such faults. In the beginning of the roll-out of wind and solar PV, such “fault ride through” standards were not necessarily applied to renewable generators and this is often still the case. This leads to renewable generators often being less robust against system faults and these generators often disconnect earlier than conventional generators during fault events. With lower shares of variable renewables on the network, their resulting system-wide effects were negligible but larger shares now raise reliability concerns in some regions, as this missing “fault ride through” potential can exhaust the existing conventional frequency reserve capacities. Remarks from ENTSO-E and the California Independent System Operator (CAISO) have already been made in this regard, focussing on solar PV installations in particular (ENTSO-E, 2011 and CAISO, 2010).

The introduction of pre-determined technical connection standards for “fault ride through” capabilities in all generators, including the renewable generators, could ensure a fair allocation of all generators’ obligations to maintaining system security. Additionally, it seems possible with ongoing decarbonisation that non-standardised responses to system faults can leave system operators with uncertainty about the quantities, timing and location of forthcoming compensated renewables. This can lead operators to compensate their uncertainty by an increasing reliance on conventional generators or other technologies (as discussed in the transmission operations section) for providing frequency reserves during system faults. This increasing reliance on only few technologies can become less cost-efficient from a system-wide perspective, especially when growing shares of renewable generators would not have to provide this service under the same technical requirements. However, the current and expected

developments, with regard to frequency response capabilities, will depend on region-specific decarbonisation rates and the deployed technologies. Careful examination of the expected costs and benefits of possible pathways and technologies should therefore result in the introduction of connection standards as demanded from ENTSO-E (ENTSO-E, 2013). This can contribute to more precise “fault ride through” requirements and also avoid massive renewable generation capacity legacies to be expensively retrofitted later on.

Coping with potential technical problems will require operational management closer to real-time and efficient network planning to determine best economic options between new investments and reliability-based generation management. Reliable generation management with large shares of small-scale renewables will require at least minimal management capabilities of small generators, as is already the case in Germany for all solar PV generation at a capacity level above 30 kW (BMU, 2012). This generation management allows the network operator to curtail the generators’ output to maintain network reliability, but in the long run this can give rise to doubts about the economic efficiency and the independency of network operators curtailing the correct sources and the right amount. In order to avoid administered curtailment through network operators, the introduction of locational real-time system prices, efficient locational operational management and the active participation of small generators are likely to become more relevant (as already discussed in the section on transmission network operations). As these generators are often owned and operated by various stakeholders, it might be beneficial to aggregate smaller generators into supply groups that can better manage their behaviour on the distribution level. To manage local network reliability problems, research (EURELECTRIC, 2013) supports the idea of a semi market-based “traffic-light” approach to prevent congestion or voltage level deviations by re-dispatching generators. Whilst this approach can be a stepwise improvement for maintaining reliability, it could continue to rely on renewable generator compensation for curtailment. As already discussed in the section on transmission network operations, such approaches could reduce incentives to renewable generators to actively participate in power markets, including the networks, and to consider most suitable individual solutions. In cases where generators’ individual decision making is informed of, and exposed to, resulting changes in total system costs, including the network, incentives to minimise system-costs could arise. Under such arrangements network infrastructures become a resource at a certain price, which can vary with generator location and can inform individual locational choice. Furthermore, the generators could also develop incentives to assess cost-efficiency of new network solutions against other solutions, such as pure curtailment during certain hours, congestion hedging, demand response or storages to overcome curtailment at the optimum time.

In cases where high system cost-efficiency is envisaged, which could be a valuable tool for reducing the potential distribution network investment needs as described above, efficiently-designed network operations will become indispensable. Efficient distribution-level network system operations help in three areas:

- congestion management;
- reactive power supply for load flow and voltage control; and
- potentially even distributed reserve operations.

They could be introduced and, comparable to the transmission operations, enhanced where necessary. Again, such operational frameworks should follow five principles:

- efficient and undistorted price formation;
- clear product definition;
- fair cost allocation to all entities, including renewable generators;
- openness and transparency;
- local accuracy.

Key findings • Capacity development of distribution-connected renewable generators can rise quickly. Technical network problems, such as potentially rising congestion, voltage and frequency level deviations are often likely to happen, requiring real-time awareness and better network and generation operations. Comparable to transmission networks, efficient and fair self-management of, and cost allocation procedures to, all market participants, including renewable generators, could yield system benefits.

Another pathway for the reliable integration of variable renewables is significant investment in new network capacity, reactive power compensators and/or controllable transformer stations to reduce, and sometimes avoid, any of these technical problems by increasing network capabilities' to integrate larger amounts of generation. Distribution network operators and generators can often miss the experience with holistic network planning and close to real-time system management under the inclusion of economic evaluations. Consequently, in the absence of efficient operational procedures, an often overly reliant infrastructure build-out can be the most likely pathway. This development can further be exacerbated by obligations to integrate the last kWh of renewable electricity independent of the associated costs, an obligation which is likely to lead into more uneconomic infrastructure investment decisions (as discussed in the transmission infrastructure section above). In light of this, research (Dena, 2012) expects that allowing for some distribution network congestion and curtailing the associated renewable generation can yield significant leverage: forgoing 2% of renewable generation would require between 13% to 21% less distribution network investments in Germany. As on the transmission level, open- and forward-looking (anticipatory) planning frameworks, fair investment cost allocation and market-based prices for distribution network operation services, such as reactive power and balancing service provisions, can potentially enhance system economics. Depending on the local circumstances, research (Dena 2012) estimates between 10% and 20% of network cost reduction potential with applied anticipatory planning. However, this would require a 20-year certainty over the market developments and any assessment failure would result in stranded and underutilised network assets. Competition between different solutions to solve technical problems is likely to become economically beneficial and voltage level controllers, reactive power compensators, controllable transformers, and dynamic line ratings and demand response or various storages can be part of the new technology mix (Dena, 2012). Further, wind generators and solar PV inverters generally seem just as capable in providing balancing services and reactive power as conventional generators or other technical devices.

Introducing these changes into the distribution network management will likely deliver significant benefits in the form of overall network investment reductions (Dena, 2012) and at least 40% investment cost reductions seem to be achievable in the specific assessed cases. However, these benefits have to be higher than the expected costs of implementation and operation and the residual system. The formation of larger distribution network areas, maybe under the operation of one responsible and co-ordinating entity, could spread the management costs over a larger amount of market participants and support network operators' capabilities to grasp the system-wide impacts of their investment decisions.

Key findings • In the absence of efficient network planning and operational procedures, an uneconomic infrastructure build-out is likely to happen, where network capacity investment can be the dominant choice. Efficiently designed and implemented distribution network operations, generators' choice and technology-neutrality between networks and other options can yield significant benefits of investment reductions.

Active demand sources and electric vehicles

So far, customers connected to the distribution network are passive load points, households and small enterprises in particular. In this regard, passive means that loads are unaware of real-time price situations for the delivery of electricity and the utilisation of network capacities in the market at a certain time. Electricity distribution networks are dimensioned for serving peak demand. High temperature regions tend to have an annual summer peak demand through the use of air conditioning, often at times when people return home from work. This is, for example, the case with Australia's NEM, where, over the period 2005-11, peak demand rose by 1.8% on an annual base, whilst annual average demand increased by only 0.5% (AEMC, 2012b). According to ENA (ENA, 2012), about 15% of the national electricity network caters for peak periods and AUS 11 billion of new network infrastructure investments have only been made to supply peak demand with an equivalent of four days per year. This shows a very low utilisation rate of parts of the infrastructure, which consequently leads to high-cost infrastructure. AEMC is projecting a customer electricity price increase by 37% between 2010/11 and 2013/14 where cost will increase on the distribution network infrastructure side by roughly a third.

With the implementation of a demand-side response programme on the distribution level, the AEMC is planning to reduce or avoid further growth in expensive distribution network infrastructure for serving rare peak demands only. Additional customer benefits are supposed to come from the benefits of buying electricity at lower prices, reliability benefits from the lower likelihood of involuntarily curtailment and long-term benefits from the reduced need for peak generation capacities. Further potential benefits can be improved risk management for customers to hedge against volatile prices or market power and environmental benefits if overall demand will be reduced. One study (IEA, 2011b) also mentions the additional benefits with renewable integration in providing balancing services in distribution and transmission networks, in matching parts of generators' over- or under-supply and variable generation patterns over shorter time frames.

Key findings • Most distribution customers are passive loads, unaware of the network costs they can cause. Regulators and operators have started to develop demand response programmes to reduce or avoid expensive distribution network investments for rare peak demand situations. Active loads can further contribute to network system services to support renewable integration on the distribution level.

All of these benefits can be determined to justify the investment costs of demand-side response technologies. Benefits should exceed the costs and these benefits will significantly vary with customer groups, demand projections, the already existing electricity network and generation infrastructure as well as the structure, transparency, reliability of the price formation(s) and the evaluation period. As already discussed in the section on transmission network investments, it is impossible for regulators or network operators to clearly identify all business cases and associated risks. Therefore regulators should rather create environments that allow for investors in the market to identify valid business cases without further regulatory decision making or regulatory cost recovery. From a central perspective, all these possible business cases are generally unidentifiable, which has led AEMC to establish the frameworks where product suppliers and customers together identify promising investment cases on a local level.

The implementation of cost reflective prices, informing customers about choices and their cost implications as well as “set-and-forget” technologies and services are considered three main items required on the customer level. AEMC further sees an active role for retailers, independent aggregators and network businesses to capture the value of flexible demand by offering innovative products also on the wholesale electricity and balancing markets. As systems vary, the recognition of locational price differences can enhance decision making for customers. Comparable to transmission network pricing, there could also be a need for the implementation of short- and long-run locational marginal prices in distribution networks as these prices could provide for higher accuracy on current, and expected, system states. On the supply side, clarity on the value of demand-side participation, information on potential network constraints and peak load developments on the distribution network, as well as access to wholesale market information, is important for creating investment certainty.

For the network-related aspects, AEMC is currently considering amendments in both the way distribution networks are planned and in the planning coordination between network planners and potential demand-side management investors. It is possible that the resulting planning framework looks similar to those outlined for the transmission level. Such planning frameworks can provide all market participants with relevant information and create a level playing field for competing technologies to solve identified weak infrastructure links. On the transmission level, this planning process will be used to identify beneficiaries and to allocate investment costs accordingly, an outcome that is likely to also support the coordination between the various beneficiaries in the business of investing in demand response at the distribution level. Accurate cost allocation is therefore required as one of the significant impediments of AEMC is currently the dispersion of benefits to several market participants, network planners, some generators, suppliers and customers.

There can be a trade-off between the benefits achievable from demand-response services provided to the electricity market and to the distribution networks. Research (Dena, 2012) predicts a potentially growing need for distribution network investments in cases where distributed demand response provides services only to the electricity market or the network. For example, in cases where excess renewable generation and resulting low market prices could trigger additional demand, this added demand could exceed today’s network capabilities and thus trigger additional investment needs into distribution networks. This example shows potential coordination requirements between the market-based and network-based benefits of demand response. A similar impact can be expected from the introduction and use of various storage technologies. Coordination of demand response and storages providing services to the electricity market and the networks can potentially become achievable by introducing two-tier real-time price formation, with different prices for the network and the electricity component.

Key findings • Benefits arising with active loads are various and can be allocated to several market segments. Inefficient pricing in potential market segments, missing customer awareness and inconvenient applicability, however, hinder the exact quantification of benefits. Two-tier real-time price formation can become relevant to co-ordinate demand and storages between network-related and market-related cost and benefits as benefits arising in the market can be overcompensated by increasing network costs, and vice versa.

Electric vehicles (EV) and plug-in hybrid vehicles (PHEV) will take some more time to significantly penetrate markets, but they are emerging as new demand sources. According to governmental policy targets, roughly 20 million electric cars will be on the roads by 2020⁵² (IEA, 2012c). Especially in states and regions with high penetration levels, such as California with expected

⁵² A target, which represents one cornerstone of an ambitious CO₂ reduction programme, of limiting long-term global temperature increase to 2°C.

1.5 million EVs by 2020 (California Energy Commission (CEC), 2009), the installed fleet will soon start to impact the existing distribution network infrastructure. Compared with the Australian case, this impact is largely driven by the time of peak use as opposed to annually rising electricity demand levels. Charging EVs is currently being discussed in at least three technological modes, each differing in the required charging time. Slow charging at level 1 will cause up to 2.4 kW of capacity demand, level 2 already demands 19.2 kW and a third, not yet fully defined level, will likely cause a demand between 20 kW and 250 kW (NREL, 2010). For comparison purposes, the regular peak capacity demand of average households is in a range between 3.5 kW and 5 kW (NERA, 2007 and MIT, 2011).

Household peak electricity demand is normally seen in the hours after work, with people coming home and switching on electric appliances. It is generally expected that EVs, if uncoordinated and without fast-charging devices, will contribute to that peak electricity demand since most drivers will return home and plug in their EV for recharging over several hours. If, in 2020, all EVs in California started charging at the same time this could cause a capacity demand between 3.6 GW (level 1) and 30 GW (level 3, lower value) in a 52 GW peak demand system. Assuming that this capacity demand by charging is aligned with predominant peak demand in distribution networks, this will add to the system's peak demand and require significant distribution and transmission network (and generation) infrastructure upgrades. Research (CEC, 2009) has calculated an incremental peak demand of up to 200 MW for California's distribution networks by 2020, provided that real-time pricing for EVs is applied. Compared with the 3.6 GW to 52 GW scenarios, this shows the massive benefits achievable through off-peak charging. Rolling out the charging infrastructure, particularly at the household level, can be designed to reduce peak impacts but leave customers with the final choice. Again, real-time price signals for distribution and transmission levels' system states and technical equipment on the connection side of the EV can prevent such massive peak impacts. Depending on the local penetration rate, such infrastructures can be most beneficial and ensure freedom of choice and customer flexibility at the same time. The latter argument is also against centrally controlled charging to avoid peak impacts. Under such a market framework, network operators would be able to shed loads from EVs at peak times to avoid congestion and reliability problems. This rigid measure is likely to make customers uncertain about expectable charging patterns and might reduce the attractiveness of EVs in general.

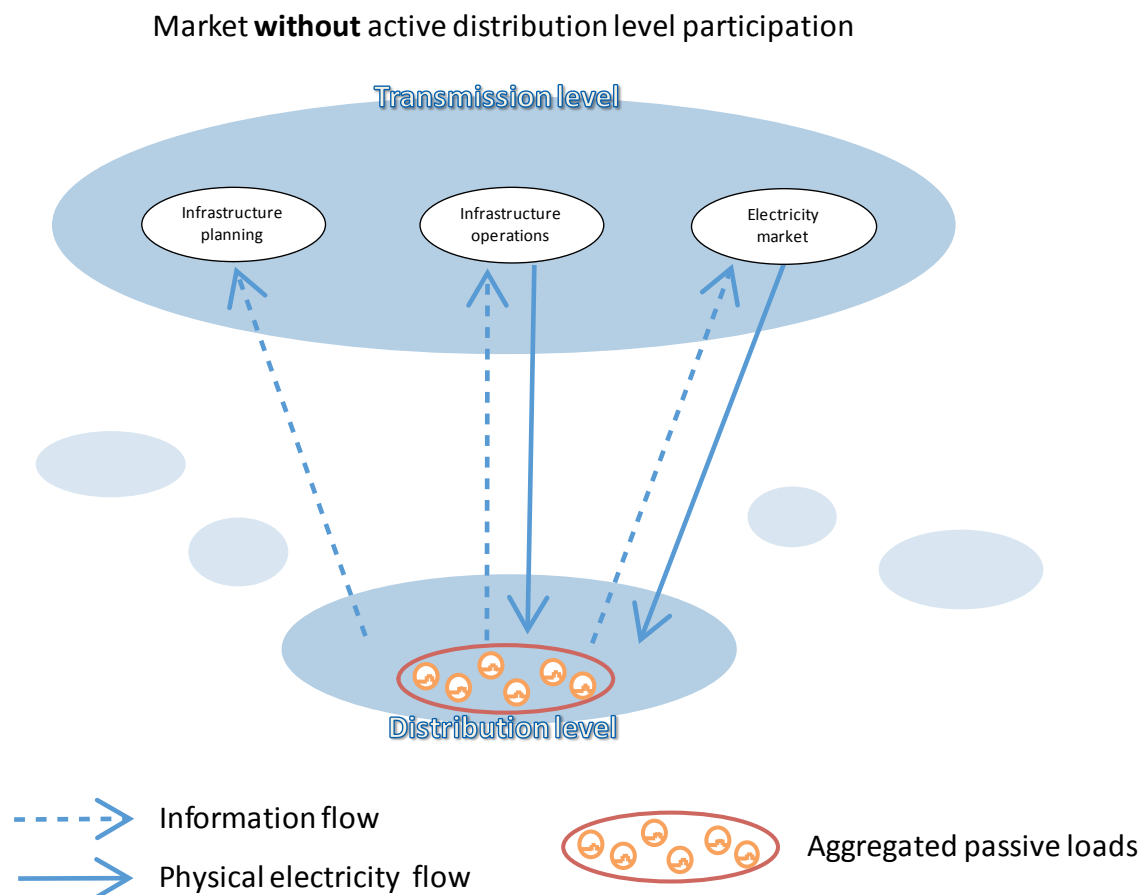
It is often argued that EVs will also be able to become a storage provider for electricity and that these storages will be usable for operational reserves or deliver flexibility for excess and low levels of variable renewable generation. However, according to one study (MIT, 2011), this bi-directional charging infrastructure is expensive, the continual recharging of batteries is likely to reduce their lifetimes significantly and the overall storage capacity will be limited due to minimum reserve requirements. It remains to be seen if EV or battery manufacturers are willing and keen to reap the potential benefits of efficiently designed electricity and/or balancing markets. Openness, predictability and efficient remuneration for delivering specific services will be essential for these technology developers.

Key findings • Peak demand levels created by electric cars can by far exceed the peak demand from households, causing high network investment needs. Comparable to active consumers, electric cars should also be able to respond to real-time electricity market and network prices to avoid increasing network investment needs. If efficient balancing markets exist, EVs' batteries can potentially become service providers.

The transmission/distribution interface

Whilst horizontal coordination between adjacent transmission network regions for network planning and operations proceeds, the vertical interface between TSO and distribution system operator (DSO) is largely uncoordinated, opaque and based upon the traditional thinking of inflexible demand and unidirectional power flows. From a transmission level perspective, distribution networks are aggregated load sinks with foreseeable peak demand as well as characteristic load patterns over seasons, months, weeks and days. Under these conditions transmission level infrastructure planning involves assessing expected peak demand levels from single distribution networks and arranging the commensurate network infrastructure. The most relevant supporting information flow to handle network operational and investment processes is unidirectional from the distribution to the transmission level so that transmission systems can prepare and adjust accordingly.

Figure 23 • Predominant electricity and information flows between transmission and distribution levels



A further layer of information flows from distribution to transmission levels comprises the arrangement of services from the electricity wholesale markets. Since distribution networks are load centres the expected short-term demand patterns will appear on the demand side of wholesale markets. This requires an efficient coordination between distributors/retailers and the wholesale market service providers. Further, generation investors will also assess the long-term development of system demand for electricity and thus will take distribution level demand developments into account.

These information flows support competitive and reliable physical electricity flows to final customers, managed on the transmission level by system operators, including balancing services and others (Figure 23).

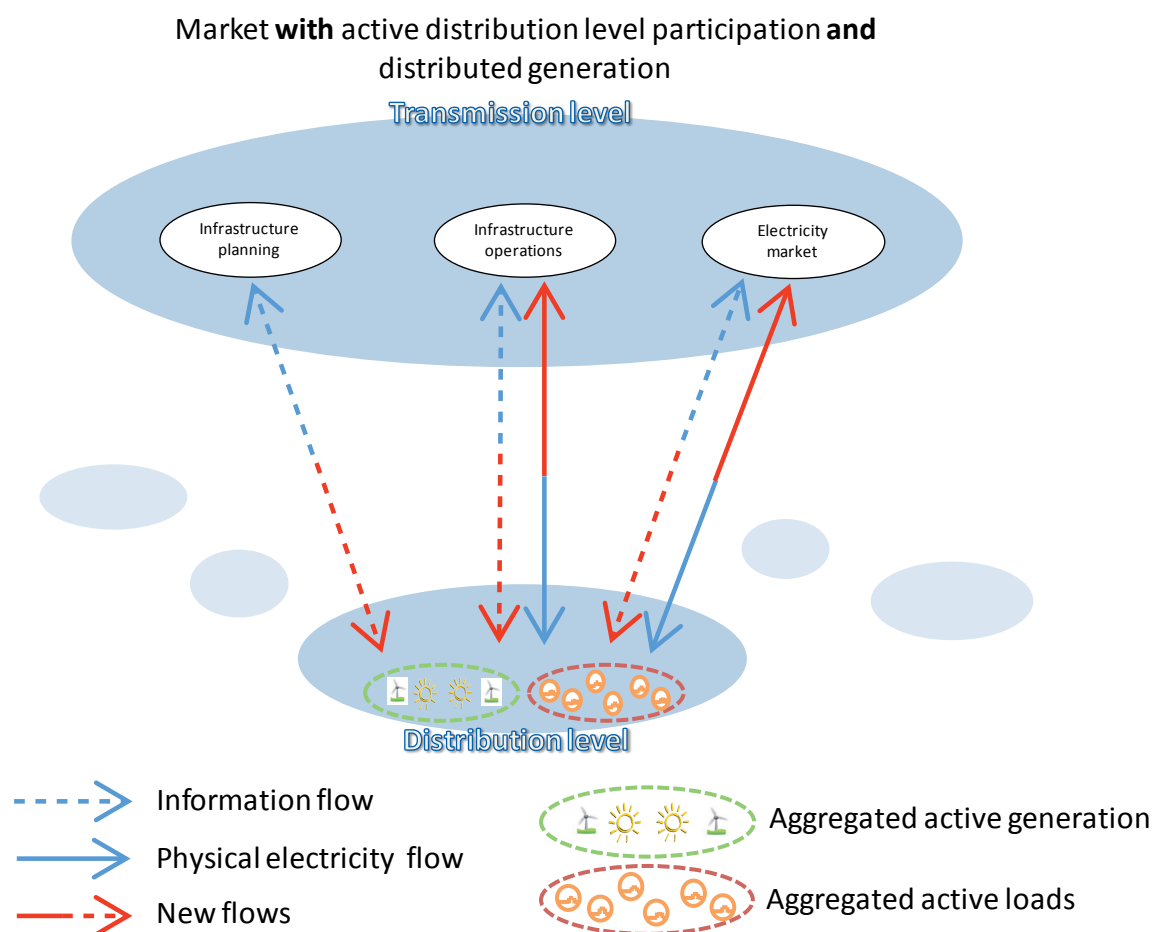
Key findings • Today's distribution networks are largely passive load centres with top-down physical electricity flows. Information flows for network planning, electricity market prices and operational procedures are uni-directional.

There are four possible benefits of an enhanced interface between the transmission and the distribution level, with three of them being supported by the uptake of demand response sources and distributed generation. These four benefits can arise from:

- better co-ordinated network infrastructure planning;
- less transmission infrastructure demand in the medium to long term;
- reliable operational service provision and coordination;
- electricity market participation.

Such an enhanced interface is based upon bi-directional information flows and bi-directional electricity flows and builds upon active distribution level customers, generators and network operators as well as efficient distribution network planning, co-ordinated with the planning frameworks at the transmission level (Figure 24).

Figure 24 • Potential outlines of enhanced interfaces between the transmission and distribution level



There will be situations where vertically co-ordinated network planning across distribution and transmission networks can bring the additional benefits of choice for the technical option(s), either on distribution or transmission, which add the highest system-wide net benefits. For the integration of new generators, and also for network reliability reasons, sometimes either distribution or transmission level solutions are possible. Imagine a generator whose generation becomes inevitable for supplying peak demand and thus now requires an n-1 reliable network connection. If this n-1 connection could either be supported by added transmission or distribution network capacity, the final chosen solution becomes a matter of costs and benefits of the alternatives, which will largely depend on the local characteristics. Especially in cases where a completely new transmission line would be required, distribution network solutions can potentially become more competitive as these lines often cause less environmental costs and public opposition. Implemented distribution infrastructure planning frameworks, comparable to those described earlier in this paper for transmission network investments, can potentially support a required level of vertical coordination.

In an open, transparent and reliable network planning framework across voltage levels, all the possible options should compete against each other as this will deliver the highest economic efficiency for electricity systems. Whilst Argentina seems to have had success in aligning distribution and transmission planning frameworks during its decade of economic growth in the late 1990s (see transmission infrastructure section), current electricity markets in most IEA member countries are only at the beginning of this process of vertically co-ordinated network planning. Further, the number of potential technical solutions has risen with the uptake of distributed generation, active demand response and sometimes storages. These developments have increased the variety of potential solutions, which can potentially deliver comparable outcomes at higher economic efficiencies. However, the solutions' nature is often, and should remain, unregulated for reaching the economic effectiveness of market-based investments. This implies that their business model, which often can consist of more than just network services, has to be valid to a large extent in a functioning electricity market with efficient price formation.

Introducing such holistic and vertically co-ordinated planning frameworks is a new regulatory concept and this implies that unforeseeable barriers might occur. More specifically, the envisaged vertical coordination raises questions on investment incentives for all potentially network developers across voltage levels, timing and regulatory approval procedures. A continuous monitoring of the effects and developments should accompany the implementation to gain the expected economic benefits.

In some cases, the investments into transmission infrastructure can also be deferred or avoided via vertical coordination. The increase of distributed generation and demand response can potentially reduce the required transformer capacity to the transmission level and potentially lessen transmission network capacity deeper in the transmission network. Such a long-term development will largely depend upon the capacity credit *i.e.* the contribution of distributed generation, often variable sources, and also demand response and sometimes storages to reliably reducing peak demand during all times. EURELECTRIC (2013) provides a less optimistic view for transmission capacity reduction by distributed generation, showing the low capacity credit of distributed generation in Puglia, Italy, where the correlation between distributed solar PV generation and peak demand is almost zero. Only if their capacity credit is significant and foreseeable on a long-term basis will transmission network planners be able to plan for less (peak) demand coming from distribution networks. And even in these cases all investment options should be assessed against each other.

Key findings • The uptake of distributed generation, demand response and storages can potentially reduce demand for transmission network capacity, but this decision should be subject to open planning frameworks. Vertically co-ordinated planning frameworks should include distribution networks, as

distribution solutions can be competitive against transmission investments. Further research, testing and implementation should assess the benefits and barriers of such vertical planning coordination.

With the uptake of distributed generation, situations where local generation exceeds local demand are likely to happen. In these cases, power flows can change directions and feedback into the transmission level, which will create an electricity market with dynamic bi-directional power flows that can continuously change directions. From the perspective of integrating larger shares of distributed renewable generation, bi-directional power flows can potentially enhance overall electricity systems' integration capabilities for variable sources as more demand and more flexibility sources can become available by accessing the transmission level. In cases where, for technical reasons such as congestion, excess distributed generation cannot be transferred into the transmission network generation curtailment can be the most economic choice for maintaining network reliability. Currently, there are different approaches to controlling small-scale renewable generators on the distribution network, with for example the Spanish TSO also managing distributed generation (see Box 5) and the DSO being responsible in Germany and the United Kingdom (EURELECTRIC, 2013). The pros and cons of these approaches should be more carefully assessed and so far there is no sufficient evidence base to compare these distinct approaches.

Other forms of network operations can also benefit from bi-directional power flows, as additional sources (from the distribution level) can offer their services. Independent aggregators of small-scale renewable generators are likely to play a significant role in forming a critical amount on the wholesale markets and transmission network service level. Such network services can comprise balancing services, to congestion management as well as to the provision of reactive power. However, to vertically co-ordinate these services efficient information exchange between stakeholders will be required. Depending on the operational design, either fully centralised at operators' level or more market-based with individual generators and/or independent aggregators, the stakeholder group's involvement in information exchange can significantly rise.

The question of whether, when, where and to what extent bi-directional flows can add net system benefits remains subject to detailed techno-economical system assessments incorporated into open and transparent planning and operational frameworks with local recognition. The results will largely depend on the investment and management costs to allow for co-ordinated bi-directionality, at least when management capabilities are required for balancing services in particular. These costs will have to be compared to the benefits that result from a reduced or mitigated generation curtailment on the distribution network level. The net benefits will have to compete against net benefits of other options, such as integration and balancing on a distribution level. For this comparison to happen it's vital to identify the balancing costs and supply options on a local basis in distribution networks, which could sometimes imply the implementation of efficient electricity and operational markets comparable to those at the transmission level. Enhanced benefits of bi-directional flows can also result from reduced generation costs on the transmission network level, from reduced network losses and potentially from alleviated congestion levels and general peak demand reduction.

Since transmission networks connect several distribution networks, bi-directionality can also contribute to smoothening loads among several distribution networks: the excess supply in one distribution network can be used to supply demand in another distribution network. Additionally, the variety and amount of distributed generators in electricity systems with large shares of renewables can contribute to balancing services on the transmission network. Aggregating the small-scale supply and demand side are concepts summarised as virtual power plants. Under such concepts, an aggregating entity will manage the power flows from the variety of small and independent distributed generators and demands (FENIX, 2008). This level of aggregation is supposed to form a critical mass of power flows, which could consequently efficiently act on the

power exchange markets and provide reliable system services. The aggregation and management of small-scale demand and supply businesses has a wide range of implications on technological, legal and regulatory requirements and also requires favourable market conditions on the retail level of the distribution network.

Key findings • With increasing shares of variable renewables at the distribution level, electricity will start to flow back into the transmission system. Electricity and ancillary service market participation should be enabled for the supply and demand side. The aggregation of small-scale market participants can be relevant to form a reliable and effective mass of power flows, but existing barriers first need to be assessed and reduced.

A higher level of vertical co-operation and integration between distribution and transmission networks can potentially yield the benefits of more affordable decarbonisation whilst maintaining reliability. However, experiences from regionally integrated markets already show that reliance on physical electricity flows across operators' boundaries will have to be carefully managed to avoid reliability problems. The IEA has undertaken various research in the field of electricity system reliability (IEA, 2005) and the 2003 blackout in Italy and Switzerland illustrates the impacts of small local system failures, which could spread out and affect many people and economies.

Box 12 • Learning from the blackouts: The “Italy and Switzerland case”

Italy’s worst supply disruption in over 50 years struck on Sunday, 28 September 2003. Parts of southern Switzerland were also affected. Cascading failure of the interconnectors serving Italy led to the separation of the Italian grid from the Union for the Co-ordination of Transmission of Electricity (UCTE) system. Separation created highly unstable operating conditions throughout the Italian system, causing widespread generator and line trips. Emergency responses were unable to arrest the situation and the Italian system collapsed.

The event started at around 3.01 am on 28 September 2003 with the failure of the Swiss 380 kV line Mettlen-Lavorgo (also known as the “Lukmanier” line). The line was relatively heavily loaded just prior to its failure, with loading levels at around 86% of maximum rated capacity. High loading levels result in overheating of conductors, which causes transmission lines to sag, increasing the potential for a short circuit caused by an electric arc between a line and a grounded object, such as a tree (*i.e.* a flashover), or possibly by direct contact with a grounded object. The Mettlen-Lavorgo line failed as a result of a flashover with a tree.

To rectify this, ETRANS (the Swiss high voltage transmission system co-ordinator) made several attempts to automatically reclose the line without success. A manual attempt at 3.08 am also failed. In a subsequent attempt to restore the situation, the reduction of Italian imports by about 300 MW took effect at 3.21 am and returned Italy close to the agreed schedule. However, the import reduction together with internal countermeasures taken within the Swiss system was insufficient to relieve further system overloads. At 3.25 am, around 24 minutes after the loss of the Mettlen-Lavorgo line, the Sils-Soazza line also tripped as a result of a flashover with a tree. Other Swiss 220 kV lines in the area subsequently tripped due to overloads, separating the southern part of Switzerland from the Swiss network. Loss of the Mettlen-Lavorgo and Sils-Soazza lines also created substantial overloads on the other transmission lines in the area. The remaining lines from Riddes and Robbia to Italy then tripped, leading to an overload on the interconnectors with France. This overload caused a significant and rapid decrease in voltage at the French border. Low voltages and high currents caused protection devices to trip the French 380 kV Albertville-La Coche-Praz line.

At this point the Italian system lost synchronisation with the UCTE network and their automatic protection devices disconnected all remaining interconnectors almost simultaneously. The Italian system was isolated from the UCTE network at around 3.25:34 am. Separation from the UCTE network created a large generation deficit of nearly 6 650 MW, which also caused a fast frequency drop throughout the Italian system. Probably due to the relative lack of available load to shed during the early hours on a Sunday morning, the reserve capacities were insufficient to prevent the ultimate collapse of the islanded Italian system. The economic cost of the disruption has been estimated at around USD 139 million.

Even though the “Italy and Switzerland case” resulted from horizontally co-ordinated physical power flows, it shows the relevance to operators to plan and operate in an integrated and reliable manner, including the overall system. A failure in a distribution network with high levels of self-generation can suddenly turn off or change an initially scheduled bi-directional power flow and/or network system service into the transmission system. Bearing in mind the Solar PV plants exceeding 4.5 GW installed in the Bavarian distribution networks, even their partial loss could result in a significant system change. The likelihood, and impact, of preparedness against such failures on distribution networks is so far not openly discussed between all relevant stakeholders. Transmission and distribution network operators, suppliers and generators’ regulators, those at policy level and other relevant bodies will need to enhance their understanding of the situation and to discuss suitable countermeasures. In this regard, the IEA work on the ESAP can be of utmost relevance to member countries as one of the five work streams will support the implementation of comprehensive electricity security and emergency management arrangement peer reviews in IEA countries (IEA, 2013).

Key findings • Physical coordination across vertically aligned operators can be as beneficial as effecting wider-area system reliability. To maintain network reliability with growing shares of distributed generation, bi-directional power flows and flow schedules, network operators must plan and operate in close vertical coordination. Adequate protection schemes will have to be determined and the IEA has started to assess the emergency preparedness of its member countries by comprehensive reviews.

Operators, regulators and electricity networks

Developments on the network levels need operators and regulators. Operators are required to facilitate the short-term operations as well as the long-term network system planning under the inclusion of all market participants. Independency, expertise, real-time awareness and real-time management capability are the four significant components that network operators are generally required to incorporate. These components will become increasingly relevant with the integration of renewables and power flows in times of financial scarcity, as distribution and transmission networks develop. Whilst the debate, on the transmission level, is about the right choice of operational structure, distribution networks must still be further developed equally without vertically-integrated companies.

At the same time, highly skilled, reliable, transparent and consultative regulators will be required to set the right regulatory frameworks where market players can make the best decisions. Regulators will have to actively apply the main aspects of infrastructure planning and siting, economic regulation, and market monitoring.

The following parts of this section describe the roles independent operators and regulations should play to catalyse an undistorted, efficient and reliable transition towards efficient electricity system decarbonisation.

Operators' role for efficient integration of power flows and renewables

One aspect of successful electricity market liberalisation was the separation of competitive generation assets from non-competitive transmission network assets. Whilst formerly integrated electricity companies delivered reliable electricity supply, their incentive to co-operate with adjacent power regions or entry-seeking generation investors or suppliers has been minimal. Vertically integrated companies,⁵³ under early regulations, often used four network tactics to avoid or hinder generation and supply-side competition:

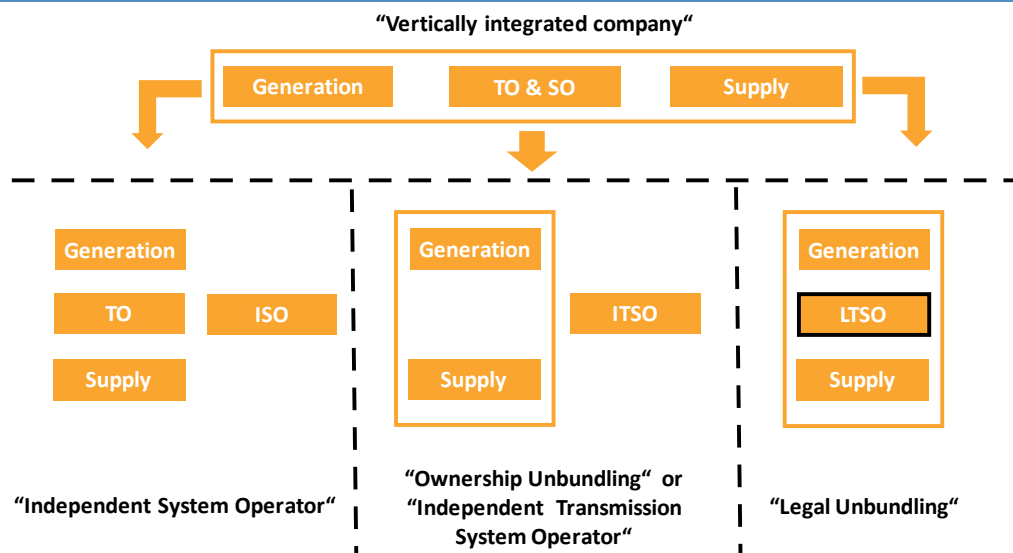
- delaying or preventing network connection processes;
- artificially increasing network connection costs;
- artificially increasing costs of network use;
- incomplete planning of new network infrastructures.

Market liberalisation continues to solve this problem of vertical integration on the wholesale level by introducing structural changes to the predominant electricity utilities. New structures and regulations had to be put in place to govern the operational and planning responsibilities of largely uncompetitive transmission networks. These changes were introduced with the intention of ensuring that transmission networks become reliable, independent and efficient facilitators for the competitive fields in the power sector. To date, the implemented structure and tasks of networks vary largely and so far there is no identified standard market design delivering best economic behaviour for the electricity sector as a whole. Most common network structures in IEA member states are independent transmission system operators (ITSO), legally unbundled transmission system operators (LTSO) and independent system operators (ISO).

⁵³ The term “vertically integrated” refers to a company structure owning generation assets and/or performing marketing activities whilst also owning network assets. In markets with unregulated vertical integrated companies, these companies can use their ownership of network assets to prevent for other market players to enter the market and compete for market shares and customers.

Within the ITSO, the system operation function is integrated with the transmission system ownership and maintenance. Fully integrating the operational and investment decisions of the system is advantageous (Figure 25).

Figure 25 • Structural choices for network-related operations and planning



The transmission assets of an LTSO remain owned by former monopoly utilities but planning and operation are legally separated from the rest of the utility. The ISO is an 'asset-light' model where the system operator does not own the transmission assets, but often takes operational and planning decisions and is involved in wholesale market operations.

While these structures, depending on the accompanying regulatory oversight, have generally facilitated new entry into the generation sector and competitive bidding and selling on the wholesale markets, distribution levels remain in a pre-liberalisation phase of vertical integration. This situation was less relevant with predominant conventional generation technologies seeking connection to the transmission networks and wholesale markets. However, as the connection of renewable generators often happens (or could happen) in distribution networks and by various new owners, the relevance of distribution-level independency rises. Transparency, data handling, real-time operational management and efficient and open network planning are additional requirements, valid for transmission but potentially also for distribution networks.

The comparison of the three structural models mentioned above remains to be further assessed to identify which model can facilitate best operational and planning procedures for integrating renewables and power flows. The crucial question is: what is the most efficient structure in an increasingly demanding environment of network management. These tasks will involve efficient tariff setting, congestion management, loop-flow handling, ancillary services coordination, close to real-time network capacity assessments as well as open network planning and expansion. All these aspects will require an efficient and real-time coordination between the wholesale market, the transmission assets as well as distribution networks and generators. Further tasks will be non-discriminatory data handling and equal stakeholder treatment and the integration of merchant investors and tenders to facilitate best investment solution planning and implementation. Facilitating competition on the operational and infrastructure level between different technical solutions and market participants as well as the availability of financial resources for new investments will have to improve.

Compared to ITSOs, ISOs currently have three advantages:

- lacking incentive for uneconomic network capacity maximisation;
- potentially non-discriminatory network planning and tendering;
- improved compatibility with adjacent operating regions.

The regulation of networks guarantees a foreseeable rate of return on investments as regulatory frameworks combine the total return on investments with the existing asset level. This combination introduces incentives for overinvestment, an incentive that cannot be overcome if asset owners are also responsible for planning future asset requirements by themselves (Pollitt, M, 2011). In a densely populated area, this task would likely come up against social resistance. At the same time, only the ISOs seem to be sufficiently independent to allow for non-regulated investments outside pure network infrastructure options to solve congestion and reliability problems. This openness can drive innovation and tendering for solutions, which can ensure a sufficient level of financial resources. This currently drives the UK ITSO to becoming an ISO for the offshore networks to connect wind parks (see Box 7) but seems to currently limit offshore network investments in Germany.

It is interesting to note that refineries and enhancements in procedures for network operations can be associated with ISO-based markets, even though this can also generally relate to more mature markets.

On the other hand, disadvantages might be the reduced regulatory influence on ISOs in general as they own no assets and this can limit the effects of regulatory incentives to these operators. Additionally, costs for implementing and operating ISOs are significant, which demands accurate cost-benefit assessments prior to implementation (Michaels, R., 2006). It remains a subject for further research and result-assessment from ongoing market experiences so as to ascertain which network structure is the best in the circumstances and to plan networks under the growing influence of power flows and larger shares of renewables.

Key findings • **Independency from generation is a prerequisite for network operators. Independency between network ownership and network planning can potentially better facilitate non-discriminatory solution finding. In electricity systems demanding new infrastructure investments, independent system operators seem to have more advantages than disadvantages compared to other models.**

Regulation accompanies network operations and investments

Under the current circumstances, networks remain regulated in terms of operational procedures, network investment and their associated costs. An important principle of electricity network regulation should be to develop, improve, and implement regulatory frameworks, which minimise regulatory decision making for the benefit of more efficient but also reliable market-based solutions. The main fields with regulatory influence in integrating power flows and larger shares of renewables into the electricity networks are derived from this report. Sound regulatory frameworks should be established and continuously evaluated and improved between regulators and all market participants with the aim of minimising the need for cost socialisation and the introduction of competition in operations and investments. Additionally economic regulations have to establish frameworks, which reduce regulatory uncertainty towards new investments. Whilst these aims have already been relevant, aspects in the short time-span post market liberalisation, the integration of (variable) renewables and developments in generator relocation have now started to fundamentally change electricity systems. Changing electricity systems from vertically integrated planning with bulky generators, foreseeable power flows and inelastic demand into split market segments, various smaller scale generators and more rapidly changing power flows will test the techno-economical resilience of current regulatory frameworks.

Facilitating efficient and competitive network operations and investments to restructure and expand the existing transmission and distribution systems are two important requirements for reaching a cost-efficient low-carbon electricity system. Mistakes will inevitably lead to reduced sector efficiency, an outcome which is particularly undesirable in the field of long-lasting new infrastructure investments. Regulators will be asked to participate in the network infrastructure planning in the way that final regulatory approval for a planned project will be required so that disputes between participants can be resolved. Sufficient knowledge for understanding and reproducing modelling results, identifying investment needs and supporting certain solutions is likely to be inevitable. According to research (O'Neill *et al.*, 2011), common modelling approaches to moderate between various investment options so far remain biased towards meeting reliability targets and thus need to be modified to accommodate the changing multi-detail nature of electricity systems.

Key findings • Regulation is no end in itself and should be minimised for the benefit of efficient market behaviour and reduced cost socialisation. Regulation should determine and accompany efficiently designed operational and planning frameworks.

Applied regulatory cost control will remain one significant aspect of applied network regulation as long as market-based solutions are not available. This economic regulation should aim at enhancing efficiency in the way existing infrastructure is replaced and restructured, new infrastructure is built and also how regulated network infrastructure operations are executed. Increasing network efficiency is necessary as network costs form a large part of total costs in electricity systems and, also affect the performance of competitive segments. Information imperfection and asymmetry between regulator and regulated company has led away from standard so called “cost of service” or “rate of return” approaches towards the development of the incentive-based regulation in theory (for a description and assessment see Joskow, P. 2006a) and practice. In the electricity sector, incentive-based approaches are spreading slowly with the most mature (but also continuously developing) approach probably being applied in the United Kingdom, while Norway and Denmark (NordReg, 2011), Germany, Australia (AEMC, 2012c) and the Netherlands have chosen different approaches. According to Ofgem, the application of incentive-based regulation has delivered 50% lower network costs since 1990 (Ofgem, 2010).

In practice, the main difference to traditional approaches is the way in which the available level of information is handled by regulators to reduce information problems and to minimise uneconomic behaviour. Regulators often apply statistical benchmarking tools, such as regressions or frontier cost analyses, to determine regulatory allowed revenues based on the costs of other companies with highest efficiency. As there are no truly identical companies, cost variations are normalised with regard to external cost drivers such as terrain and demand/supply structure (Jamasb, T and Pollitt, M., 2000), etc. For electricity networks, the application of such benchmarks can assist in identifying efficient costs for the provision of services and investments and companies with higher costs or lower outputs are considered as inefficient. As benchmarking cannot solely be settled on theoretical grounds, regulators often apply sensitivity analyses and several benchmarking models. This is the case in Germany where two models were used to identify the best performing companies (ARegV, 2007).

Data availability to accurately handle the benchmarking methodology is one fundamental of the quality of data involving capital, operational and financial cost figures, and their accounting rules as well as identified inputs to be measured against these costs, such as supplied electricity, length and density of the network, terrain etc. As capital and operational costs are interchangeable to a certain extent, regulators should avoid a one-sided benchmarking-incorporation of costs so as not to trigger cost spill-over effects. These spill overs can also be prevented by not incorporating

quality aspects⁵⁴ as without such recognition, incentives for maintaining or achieving a desired quality level would fail in the medium- to long-run. The UK approach includes quality incentives based upon desired standards, where rewards and penalties apply for distribution companies depending on the achieved performance (Ofgem, 2012d) and the German approach measures efficiency levels for distribution network companies based upon capital and operational costs (ARegV, 2007).

The incentive-based approach is a forward-looking approach in which the regulatory determined amount of revenues will be identified *ex ante*. The incorporated targets for efficiency improvements can be achieved over the course of several years during the so-called regulatory periods of usually four to eight years. The period is one significant aspect of the incentive regulation approach as companies are allowed to keep the difference between the allowed revenue and their actual revenues. Companies' behaviour within the period is what usually interests regulators as this reveals efficiency levels that will often be applied in the subsequent period's revenue determination. This incentivises efficiency maximisation at the beginning of each period as this maximises the time span for keeping these extra benefits and also implies stronger incentives for efficient network investments over growing periods of time. After a five-year period, Ofgem now has implemented an eight-year regulatory period, which is targeted at increased efficiency incentives (Ofgem, 2010).

Incentive regulation is complex and remains subject to continuous trial and error as well as improvement (Joskow, 2006). To date, there is no stable approach, which delivers full cost efficiency for existing assets and operational costs as well as for new investments; a fact that demands a continuous comparison of internationally applied models. In fact, significant parts of new investments remain subject to traditional cost of service approaches outside any benchmarking approaches as these investments are not straightforward and derive from historic efficient investment patterns (Joskow, 2006). In light of this, new investments for transmission network operators are often derived from network companies' investment plans (see planning section) and tested⁵⁵ and approved by regulators outside the incentive scheme. The German incentive regulation combines these approaches by first approving costs at the transmission level outside any benchmarking determination then later merging the approved costs with the following benchmark. At the same time, the UK model uses a so-called sliding-scale approach for new investments at the distribution level, where the company is free to choose the cost of service regulation and investment incentives, which is designed to better represent each companies' status of investment needs (Ofgem, 2004). This approach has been amended recently by Ofgem's new approach of output-oriented regulation, where cost efficiency is now accompanied by defined outputs to be achieved for each transmission and distribution network company specifically.⁵⁶ Commensurate incentives apply to each of these companies.

Independent of the application of regulatory methodology, the investment certainty can be affected by the way network costs are treated. *Ex ante* or *ex post* treatments are two general options in this regard. *Ex post* regulation determines the efficient network costs based upon actual investments undertaken by investors as well as regulatory cost assessment. This approach can introduce less regulatory efforts compared to an *ex ante* approach. The main difference in the *ex ante* approach is the required comparison of the actual investments and the investments approved *ex ante*. These assessments can require a significant amount of regulatory capacities. Without a stringent regulatory cost comparison, an *ex ante* approach could even incentivise an

⁵⁴ such as quantity and scope of interruptions, performance standards or (telephone) service quality.

⁵⁵ often based upon techno-economical investment models.

⁵⁶ such as reliability, availability, customer satisfaction, connection times, environmental (including losses) and capacity additions.

inflated investment plan. On the other hand, the ex ante approach can have a significant positive impact on the investment certainty of network investors. If an investor knows the approved investment costs before the investment happens, the cost recovery plan can often be less risky.

Key findings • Regulatory cost control for operational costs, costs of restructuring and expanding the networks is important as long as merchant investments and market-based operations are insufficient. Information asymmetry also influences this interface between regulators and regulated entities. Incentive-based regulation can reduce this information asymmetry, but requires further research and international best-practice comparison to determine best approaches, for new infrastructure investments in particular.

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Next to the development of regulatory frameworks and the application of regulatory cost control, regulators will also be required to supervise electricity markets and the role and behaviour of their market participants. Detailed dispute resolution between various entities and within various network related aspects would also have to be consultative and transparent for the purposes of a reliable market. As accurate markets develop and new financial and physical products are offered by an increasing number of market participants, market power is likely to become generally more visible and more spread out into several segments of the sector. Market oversight, analytics and surveillance should follow all these developments in the required level of detail to turn educated guesses of market power abuse into precisely identified uncompetitive behaviour. As generation-related aspects are closely connected to network-related aspects, this oversight should either be concentrated within one authority or perfect liaison between different institutions enabled.

Regulators involved in the infrastructure planning and cost approval process will also have to closely co-operate with other relevant authorities over infrastructure siting. Other options are to bundle all relevant siting tasks, which are currently often undertaken by various regional and local authorities, under one regulators' authority while maintaining the required local knowledge base. Finally, international exchange of best regulatory practices and experiences should be institutionalised and professionalised as this can help boost development in a constantly growing environment of sector regulation.

Expertise should be developed at with enough experts and skilled decision makers in the various fields related to electricity networks, including techno-economic knowledge in particular.

Key findings • Further regulatory tasks will be dispute resolution, monitoring of market power abuse and infrastructure siting in close coordination with other responsible agencies. International exchange between regulators should be equally important as the staff level expertise.

Recommendations and research challenges

In this paper, significant challenges for the transmission and distribution networks, which result from the integration of power flows and large shares of renewables, were assessed. The main recommendations for policy makers, regulators, system operators, network developers and other stakeholders can be derived from the 13 important findings throughout the text:

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- Ensure operators have sufficient real-time situational awareness and power flow management capabilities and co-ordinate with adjacent markets and the distribution level.
- Acknowledge the relevance of electricity networks as well as the need to allocate their costs to cost responsible users rather than to socialise among all users.
- Focus on improving the various frameworks, services and capabilities for, and on, the distribution level.
- Empower efficient customers to become aggregated. Evaluate the need for two-tier real-time prices for electricity and networks to efficiently co-ordinate these segments.
- Maximise use of the available networks with sound regulations, which take system-wide views to minimise system-wide costs.
- Implement open, consultative and transparent planning frameworks, economic regulations and embedded siting procedures to identify and deliver new investments in distribution and transmission, which bring added system value.
- Use the network to guide the location of generators to establish least-cost systems and ensure network investments do not follow the generators.
- Try to establish the added market value of renewable generation to support quantitative network investment assessments and planning.
- Enhance network system services and co-ordinate with the electricity market to achieve operational and dynamic efficiency, to solve the flexibility question, to reduce electricity market price distortions and give support to avoid conventional generators' missing money problem as well as heavy handed regulations and market interventions during the transition.
- Permit renewable and other market participants to play an active role in the network service provision and use and allocate network service costs commensurate to the benefits and the responsible parties. Do not discriminate against new service technologies or favour conventional generators, which can be subject to declining market shares and market exits.
- Enable the institutions to enhance system service frameworks and provision.
- Look abroad to exchange, find and develop best practice solutions and continue to develop these further.
- Introduce all rule changes before the system starts to change significantly change as amendments take time but decarbonisation can be rapid.

In various aspects, there is still a need for further research, testing, evaluation and continuous improvement of frameworks. Three significant aspects are relevant to the changes in network management for the networks to overcome the challenges of the next decades:

- distribution level aspects with regard to networks, demand, generation, services and the interface with the transmission and wholesale level;
- reliability management in increasingly inter-regional systems with multiple and often small-scale market participants and increasing levels of flow distances and dynamics; and
- institutions and economic regulatory frameworks for efficient network infrastructure investments.

Annex

Nodal congestion management and transmission rights

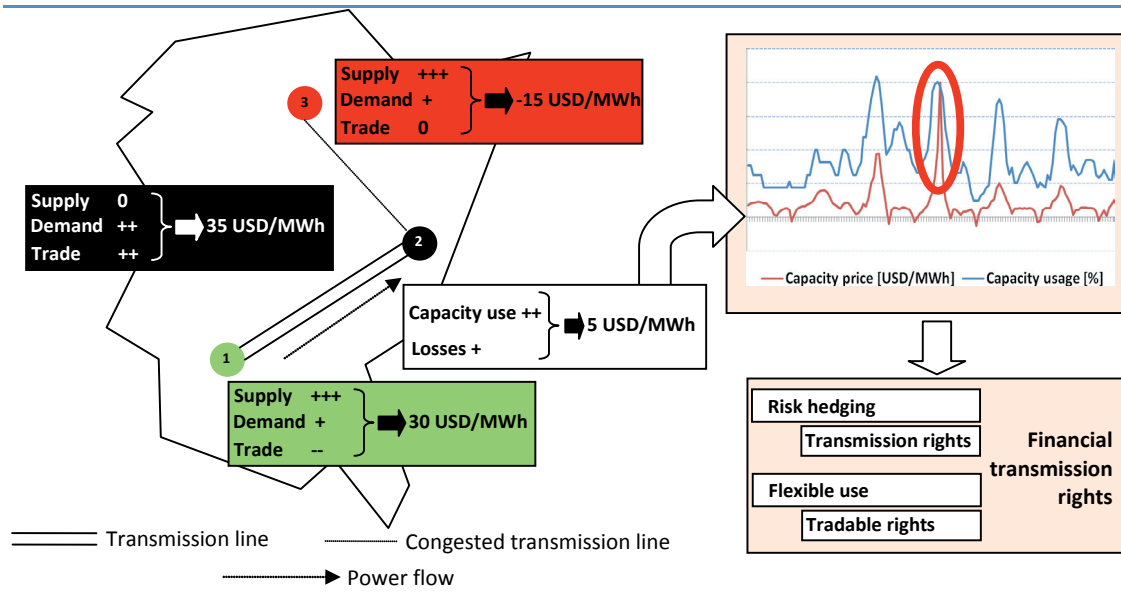
A node is the smallest relevant physical connection point for supply and demand on the transmission level and each node is linked to one or several other nodes via transmission lines. Operators are well aware of the available capacities of transmission lines, geographical and other relevant technical conditions between nodes. In light of this, they are also able to calculate the costs of network use for supplying the next (marginal) unit of electricity between two nodes over time.

Nodal management reveals the real physical conditions on the transmission network and identifies the supply/demand balance of each node. There are often nodes with a general generation overcapacity and nodes with a general generation capacity shortage and this imbalance leads to the use of the transmission system between nodes. Using the transmission capacities requires their sufficient availability and insufficiency/scarcity will be expressed in increasing prices for nodal network system use. As network losses are also driven by an increasing use and transport distance between supply and demand nodes, costs for network losses compensation can also be indicated in the prices for such nodal system usage. Both factors vary with the degree of network utilization and the degree of utilization varies with demand and supply fluctuations, so price variations for network system use can vary, as on the wholesale markets for electricity.

Operators can ex ante determine the operational costs of transmission system use between nodes and thus create real-time and locational differentiated prices for network system use. Generators implicitly take these prices into account when they bid in the electricity market and these costs will appear as additional operational costs to their short-run marginal generation costs. Depending on the electricity systems' state, this implicit ex ante short-run cost calculation with locational reference can have an effect on the merit order as it accounts for full operational system costs (generation and transmission) in advance. It thus represents a market-based instrument to establish a more accurate market settlement and, by doing so, contributes to minimising the total operational costs of electricity systems. LMP also allocate significant parts of the operational network costs to the causer so that these costs no longer have to be partly or fully socialised between system users. Such cost allocation can be achieved via the auctioning of tradable transmission rights for system use between the network operator and network users. A properly designed auctioning mechanism and liquid market also reveals each generator's willingness to pay for certain transmission rights.

Nodal pricing significantly affects the operational costs of one power plant, located at the green node (Figure A1). Suppose the generator supplies the demand at its reference node at a generation costs of USD 25/MWh and due to the close location to the customer no network losses and network congestions arise. If the same generator wants to supply demand at the yellow node, the resulting electricity flows between the green and the yellow node will cause network losses and capacity use, both at a total additional cost of USD 25/MWh (USD 10 + USD 15/MWh). The generators' total operational costs will then be USD 50/MWh. In this case, another generator located at the yellow node has a comparative advantage if his generation costs are at USD 40/MWh and there are no losses or congestion costs to be accounted for. In a nodal system, this would lead to the generator at the yellow node being dispatched to supply the demand at this node, while a system without ex ante full operational cost accounting would prefer to dispatch the generator at the green node.

Figure A1 • Locational marginal pricing and financial transmission rights



Acronyms and abbreviations

AC	Alternating Current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
ARegV	Anreizregulierungsverordnung
AUS	Australian Dollar
BMJ	Federal Ministry of Justice (Bundesministerium der Justiz)
BMU	Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit
BMWi	Bundesministerium für Wirtschaft und Technologie
BANANA	Build Absolutely Nothing Anywhere Near Anyone
BPA	Bonneville Power Administration
BNetzA	Bundesnetzagentur
CAD	Canadian Dollar
CAISO	California Independent System Operator
CAPEX	Capital Expenditures
CAPM	Capital Asset Pricing Model
CBA	Cost-Benefit Assessment
CEC	California Energy Commission
CECRE	Spanish Control Centre for Renewable Energy
CER	Commission for Energy Regulation
CIGRE	International Council on Large Electric Systems
CIP	Canadian Institute of Planners
CO ₂	Carbon Dioxide
CORESO	Coordination of Electricity System Operators
DCENR	Irish Department of Communications, Energy and Natural Resources
DC	Direct Current
DECC	Department of Energy and Climate Change
DLR	Dynamic Line Rating
DSO	Distribution System Operator
EC	European Commission
EEG	Gesetz für den Vorrang Erneuerbarer Energien (Erneuerbare-Energien-Gesetz)
ENA	Energy Networks Association Australia
ESAA	Energy Supply Association of Australia
ESAP	IEA Electricity Security Action Plan
EnBW	Energie Baden-Württemberg
ENTSO-E	European Network of Transmission System Operators for Electricity
EP	European Parliament
EPG	Electric Power Group
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ESAP	Electricity Security Action Plan
EUR	Euro
EWEA	European Wind Energy Association
EV	Electric Vehicle
FACTS	Flexible Alternating Current Transmission Systems
FERC	Federal Energy Regulatory Commission
FIT	Feed-In-Tariffs
FSC	Fixed Series Compensation
GE	General Electric

GPA	Group Processing Approaches
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IRC	ISO/RTO Council
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
IT	information technology
ITSO	independent transmission system operator
KNi	Klaus Novy Institut
LMP	Locational Marginal Pricing
LTSO	Legally Unbundled Transmission System Operators
Minetur	Spanish Ministry of Industry, Energy and Tourism
MISO	Midwest Independent System Operator
MIT	Massachusetts Institute of Technology
NARUC	National Association of Regulatory Utility Commissioners
NEM	National Electricity Market
NEP	Netzentwicklungsplan
NERC	North American Electric Reliability Corporation
NGET	National Grid Electricity Transmission
NGO	Non-Governmental Organisation
NIMBY	Not In My Backyard
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
OCGT	Open Cycle Gas Turbine
OECD	Organisation for Economic Co-operation and Development
Ofgem	Office of Gas and Electricity Markets
OFTO	Offshore Transmission Owner
PHEV	Plug-In Hybrid Vehicles
PJM	PJM Interconnection Regional Transmission Organization
PMU	Phasor Measurement Units
PUCT	Public Utilities Commission of Texas
PV	Photovoltaic
RAB	Regulated Asset Base
RAP	Regulatory Assistance Project
RED	Red Eléctrica de Espana
RET	Australian Department of Resources, Energy and Tourism
RGI	Renewables Grid Initiative
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
SCADA	Supervisory Control and Data Acquisition
SO	System Operator
SVC	Static VAR Compensators
TO	Transmission Owner
TCSC	Thyristor Controlled Series Compensation
TSC	Transmission System Operator Security Cooperation
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
UK	United Kingdom
US	United States
USD	US Dollar

US DOE United States Department of Energy
WAMS Wider Area Measurement Systems

Units of measure

bn	billion
GW	gigawatt
GWh	gigawatt hour
h/a	hours of full load per year
km	kilometre
kV	kilovolt
kVAr	kilovar
MVAr	megavar
m	metre
kW	kilowatt
MWh	megawatt hour
VAR	Voltage-Ampere Reactive

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