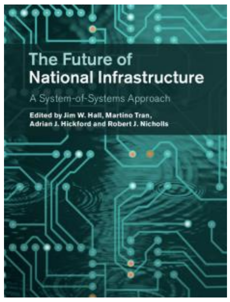
Appendix B

ITRC Energy Systems Modelling & Analysis Methodology



1. State of the art in energy demand modelling

National energy demand models can be sectorally explicit (e.g. UKDCM) (ECI, 2007) or nationally aggregated (e.g. ENPEP) (Conzelmann, 2001). Sectorally explicit models typically estimate final energy demands by major fuel types and/or end-uses in sectors. Models with an energy supply centric analysis capability typically focus on evolution of supply-side energy mix (e.g. MARKAL) (LouLou et al., 2004). Demands resulting from acquiring/producing and supplying energy (e.g. electricity production and transmission) are added to end-use consumption to produce final demand. However, they often have limited representation of sectoral level demand drivers and end-use energy services demand may be exogenous to the models. Models with an end-use demand modelling focus (e.g. MAED) (IAEA, 2006) may only focus on consumption at the economic sector level, thus lacking a supply module and not producing total national fuel demands. On the other hand, in models like NEMS (EIA, 2009), both demand and supply-side drivers and options are incorporated in detail and in a flexible manner so that it can be used both for short-term prediction as well as long-term scenario analysis for planning and policy evaluation. A rapidly changing world and increasing uncertainty in the energy system means that such an expansive approach is gaining preference in recent years despite its additional complexity and data/resources demand.

Both simple and sophisticated modelling approaches have been adopted depending on the model requirements and availability of data/resources (Swan and Ugursal, 2009; Bhattacharya and Timilsina, 2009). Simple models may take growth-based, elasticity-based, specific consumption or energy intensity-based approach for future estimation of national/sectoral energy demands based on past trends in sectors or major energy carriers. In rapidly growing economies, with strong relationships between demand and its drivers and clear trends in structural shifts in the economy, such an approach could produce acceptable future estimates of demand. These models however can neither explain nor capture the wider underlying (and emerging) demand drivers, technological changes and structural shift dynamics explicitly.

Sophisticated approaches may take econometric, engineering-economy (a.k.a. end-use) or hybrid approaches for simulating/predicting energy demand. Econometric models estimate energy demand based on economic relationships constructed from past data. While these models can capture changes in aggregate demand from global drivers, such as GDP and energy price, non-price related policies as well as technological and structural changes are often not captured. Engineering models are bottom-up and estimate energy demand in defined end-use categories with explicit or stylised technological representation. With macro-economic links, this approach can assess different policy options and provide process-based analysis of long-term evolution of energy demands under varying technological, social and economic drivers affecting the energy system. Based on the model goal, end-use models can take a simulation (e.g. MAED) or optimisation approach (e.g. MARKAL). In a changing and uncertain world, engineering-economy models with a scenario approach can provide critical insights for robust and adaptive policymaking from analysis of illustrative alternative pathways of energy system evolution. As the name suggests, models with hybrid approaches (e.g. NEMS, POLES) (EIA, 2009; JRC, 2010) combines two or more approaches to overcome limitations in individual approaches and present a holistic framework to capture the energy-economy and energy-society interactions.

Other major approaches are economic input-output based analysis (Nathani et al., 2006), system dynamics models (Hannon et al., 2001), general equilibrium models (e.g. GEM-E3) (Bahn and Frei, 2000) and multi-agent models. Input-output models can capture detailed links of the energy system with intra/international economic attributes and can estimate energy system's environmental impacts using highly disaggregated economic attribute flow and energy demand data. Since these models are often a snapshot in time, the capabilities to assess impacts under long-term technological and socio-economic changes are often limited. As the name suggests, system dynamics models are capable of representing dynamic inter-system links (e.g. between energy-economy and energy-society) over time. However, calibration is cumbersome and capability for detailed analysis and simulation involving multiple subsectors, end-uses and regions are limited in current modelling platforms. This limits spatial scenario-based investigation of a range of socio-economic and structural changes into the future. To start with, general equilibrium models (GEM) assume all markets are in perfect equilibrium. This equilibrium is preserved by adjusting prices by involved agents (households, firms etc.) to maximize welfare or profits under certain constraints. Advantage of GEM lies in its ability to simulate energy system's wider interlinks with economy, environment and macroeconomic policies (e.g. taxes, subsidies etc.). However, by virtue of its approach, important long-term transition attributes, such as, technological details, energy efficiency gaps and market failures and barriers are neglected. In contrast to GEM, multi-agent models recognise that market is imperfect. The approach emphasises the role and actions of agents in view of asymmetric information in the market and other non-economic drivers in agents' decision-making in driving demand and supply. Uses of artificial intelligence based learning means models often require enormous empirical data to simulate behavior of agents. Current uses are seen mainly in energy conversion technologies and operational analysis rather than long-term sectoral energy systems analysis (Herbst et al., 2012).

Models with an engineering focus of the energy system often take a hybrid approach and are parameterized accordingly. The three sectoral accounting-simulation energy demand models developed in ITRC take a hybrid energy intensity and engineering end-use approach as explained in section 3.3.1. The CGEN+ model, developed for gas and electricity infrastructure expansion planning, takes an engineering optimisation approach and is described in section 3.3.2.

2. State of the art in energy supply modelling

Gas and electricity network operation and infrastructure planning is conventionally carried out independently. Gas network expansion planning responds to demand from various sectors (residential, industrial, and power) resulting in appropriate infrastructure reinforcements. Similarly, electricity network planning is closely linked to future electricity demand and retirements/additions of power plants.

Natural gas price contributes significantly to the final cost of power generated by gas-fired plants and the larger the capacity of gas-fired generation, the stronger the link between gas and electricity networks and markets. Therefore given a power generation mix with a large share of gas-fired plants, any increase in gas price strongly influences the electricity price and subsequently economic competitiveness of the gas-fired plants in the electricity market.

In an energy system with large capacity of gas-fired power plants, the capability of the gas network to supply gas demand to the power sector is crucial and affects the optimal operation of the electricity network (Munoz et al., 2003; Li et al., 2008). In such an integrated system, an interruption in the gas network not only constrains the ability to meet gas demand but could also disrupt electricity supplies (Chaudry et al., 2008). Li et al. (2008) analysed the impact of interdependency of electricity and natural gas networks on power system security using an integrated model. The model took into account the natural gas network constraints in the optimal solution of security constrained unit commitment. Shahidehpour et al. (2005) investigated the impact of natural gas infrastructure contingencies on the operation of electricity networks.

Studies on the single and multi time period operational optimisation of the gas and electricity network were investigated in (Chaudry et al., 2008; Qadrdan et al., 2010). In (Chaudry et al., 2008) the advantages of operational coupling of the gas and electricity networks was demonstrated by quantifying the consequences on each network as a result of gas supply infrastructure outages. In (Qadrdan et al., 2010) the impacts of abrupt changes of power output from gas fired generating units, to compensate variable power output from wind farms, on the GB gas network were analysed.

Gas network planning optimisation through pipe expansion was described in (Andre et.al, 2009). The weaknesses of different algorithms for solving the planning optimisation problem were also discussed in Andre et al. (2009). Very few studies have explored the combined operation and expansion planning of gas and electricity network infrastructure. Detailed expansion planning of the combined gas and electricity network was developed and studied as part of the ITRC project (Chaudry et.al, 2014).

3. Modelling framework and model description

ITRC adopts a modular soft-linking approach to model and investigate the Great Britain (GB) energy system with an infrastructure transition perspective under an uncertain future. Three bespoke demand simulation models for residential, services and industry sectors, capable of representing a comprehensive set of sector-specific end-use transition options, are developed. Transport energy demand and required parameter data are obtained or derived from outputs from a bespoke transport services demand model developed within the consortium (refer to chapter on the transport model). With an optimisation approach, the energy supply infrastructure model CGEN+ carries out detailed and integrated investigation of gas and electricity infrastructure expansion to meet various demand regimes. To ensure consistency, key assumptions in transition strategies are harmonised in a systematic way across the sectors. Figure B-1 shows the schematic of energy demand and supply models with major input/output flows and harmonisation links. Outputs from the energy supply model are further used to investigate water implications of electricity generation (not shown in Figure B-1).

The framework ensures that both demand and supply side demand drivers and transition options could be modelled and investigated for a wide range of socio-economic futures to draw critical infrastructure-specific insights in major energy carriers, namely electricity and natural gas.

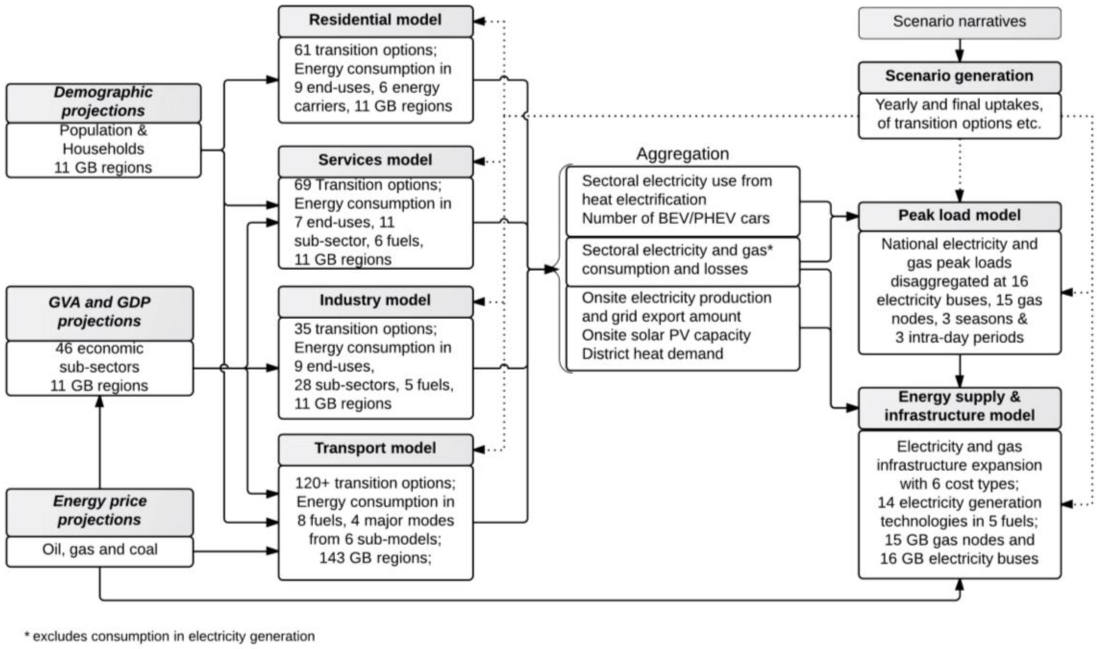


Figure B-1 ITRC energy modelling framework with sectoral models and inter-model links

3.1. Energy demand model

Developed sectoral demand models use a hybrid approach of energy intensity and end-use demand modelling to estimate *changes* in demand over base year from evolution of global demand drivers (ITRC scenarios) and uptake of transition options (ITRC transition strategies). Transport energy demand is derived from a transport services model.

3.1.1. Model capability and limitations

Each sectoral demand model has a comprehensive set of sector-specific end-use transition options to represent future pathways. The models allow specification of uptake start year, market diffusion level and final desired uptake level and saturation year of each transition option. Table B-1 lists the model inputs and transition options in the 3 demand models.

Using a perfect foresight back-casting simulation approach the models can generate an ensemble of pathways that reach envisioned/desired future states. Spatio-temporal disaggregated demands at specified sub-sectors, fuel carriers and end-uses are generated.

Table B-1 Inputs and transition options in sectoral and peak demand models

	Model inputs including transition options			
	Residential sector model	**Services sector model**	**Industry sector model**	**Peak demand model**
Global drivers - socio-economic	• Yearly regional Population & Household size	• Regional sub-sectoral GVA	• Regional sub-sectoral GVA	• Total & sectoral electricity/gas demands • EVs/PHEVs penetration • Electricity demand from heat pumps
Global drivers - climate change	• Change in regional external temperature	• Change in regional external temp.		
Base- year energy demand	• Disaggregated demand by region, end-use and fuel	• Disaggregated demand by sub-sector, end-use and fuel	• Disaggregated demand by sub-sector, end-use and fuel	
Transition options: Conservation	• Smart display induced • Space heating/cooling • Per capita hot water usage	• Catering • Computing • Space heating/cooling	• Compressed air - management action [3] • Smart meter induced savings	• Demand response
Transition options: Energy Efficiency	• Building envelope efficiency (average leakage rate) • Boiler efficiency • Lighting efficiency • Appliance efficiency	• Building envelope efficiency ((average leakage rate) • Passive cooling & ventillation • Lighting efficiency/ controls • Oven & refrigeration efficiency • Computing - mode switch & efficiency • Space/water heating - BEMS, HVAC, heat recovery, efficient boilers	• Motors, lighting, compressed air [3] & refrigeration efficiency • Energy reuse in low tempperature process and space heating • Iron & steel - BAT, substitute • Cement - Dry/wet process, novel cement • Sub-sector wide efficiency	• Smart grid (AMR) penetration • Peak hour charging/discharging regime (G2V/V2G) • Demand response (other than from V2G) • Smart grid enabled transmission efficiency
Transition options: Alternative technology / Fuel switch	• Cooking - gas to electric • Space and water heating - incumbent to alternatives [1]	• Space and water heating - incumbent to alternatives [2]	• Iron & steel - BAT, substitute • Cement - Dry/wet process, novel cement • Low temperature process and space heating - incumbent to alternatives [4]	
Transition option: Onsite generation	• PV penetration (Wp/person) • CHP penetration • Hot water demand met by solar thermal heating	• PV penetration • CHP penetraton	• CHP penetration	
Other inputs	• Regional yearly & 20-year average degree days • Average dwelling size and relative floor area by type in base year; dwelling size by type relative to base year in each year • Average yearly efficiency/CoP of heating, cooling and cooking systems • Relative stock of standard gas and condensing gas boilers in base year • Relative stock of lighting technologies in base year • Savings rate of switching between lighting technologies • Grid export (%) of PV & CHP-produced electricity Uptake S-curve of each option [1] Std. & Condensing Gas Boiler, Oil Boiler, Solid Fuel Boiler, Biomass Boiler, ASHP, GSHP, Stirling CHP (electrical+thermal), Fuel Cell (electrical+thermal), District Heating, Gas hob, Electric induction hob, Solar PV (load factor), Solar thermal (for hot water)	• Regional yearly & 20-year average degree days • Average yearly efficiency/CoP of heating and cooling systems • Relative stock of standard gas and condensing gas boilers in base year • Relative stock of lighting technologies in base year • Savings rate of switching between lighting technologies • Minimum savings from switching from standard to CFL/LED lights; relative base year lighting load from standard lights • Relative heating and cooling loads in HVAC systems • Relative demand from refrigeration in specified categories • Buildings with BEMS in base year [2] Air-conditioner, Refrigerator, Std. Gas Boiler, Oil Boiler, Solid Fuel Boiler, Biomass Boiler, ASHP, GSHP, Stirling CHP (electrical+thermal), Fuel Cell (electrical+thermal), District Heating, Solar PV (load factor), Solar thermal (for hot water)	• Average efficiency of heating systems in space and low temp. process heating [3] Potential savings from management and technical options are combined [4] Industrial Heat Pumps, Natural gas CCGT CHP (electrical+therma), Fluidized Bed Biomass CHP(electrical+thermal)	• Historical electricity/gas seasonal and diurnal peak load profiles (for BaU) • Charger characteristics of EVs/PHEVs • Range requirements of EV/PHEVs • Battery characteristics of EV/PHEVs - conversion efficiency, storage capacity, discharging power etc. • Uptake S-curve of each option

Because of the rich scenario capabilities, the models can investigate implications of non-price policies and structural and behavioural changes on sectoral demand. Impacts from long-term evolution regimes of demand drivers, such as, demography, GDP and climate, can be investigated. Since the models do not rely explicitly on historical values for future demand estimation (except for demands and technology stock in base year), problem of multi-collinearity is avoided. With detailed end-use and technological disaggregation, impacts from new /emerging technologies, including microgeneration, can be explicitly modelled.

In the models, transitions such as inter-fuel substitution do not depend on price or demand elasticity, with the recognition that evolution of these parameters can be uncertain in the long-term, especially for new technologies or energy carrier types. The approach assumes that technological solutions are more likely to gain public acceptance than taxation and pricing policies to reduce energy consumption and greenhouse gas emissions (Swan et al., 2009), and is of greater importance to investigate the range of transition possibilities over next few decades. This is also in recognition to the increasingly accepted view that, transitioning the incumbent energy system to one fit for the 21st century, capable of meeting multiple challenges including deep decarbonisation, will require going beyond current set of price or cost-centric policies and measures.

The approach taken here means price based signals and price-based policy measures have to be implicitly implied through temporal representation of transition options or demand reduction. Also, adaptive or optimal system change pathways are not outputs of the model and have to be explicitly presented in transition strategies. Instantaneous demand changes from changing prices as a result of long-run elasticity can be investigated (not investigated for this study).

3.1.2. Demand calculation:

ED	: Energy demand	
EDFrozenTech	: Energy demand with technology mix frozen at base year	
ScenarioDriver	: (Product of) global scenario driver(s)	
EDCBehavMngtChange	: Energy demand change from behavioral change and other conservation/management measures	
ERREfficiency	: Energy demand reduction from energy efficiency	
EDRedFuelSwitch	: Energy demand reduction from switching to alternative technologies (e.g. gas boiler to heat pumps)	
EDIncFuelSwitch	: Energy demand increase from switching to alternative technologies (e.g. gas boiler to gas CHP)	
EDRedReuse	: Energy demand reduction from energy recovery and reuse	
EDRedOnsiteGenUse	: Energy demand from use of onsite energy production (e.g. PV, CHP)	
EDBeforeSwitch	: Energy demand prior to fuel switching	
SwitchFraction	: Fraction of *EDBeforeSwitch* to be switched to alternative technology set	
CurrentTechEff	: Efficiency/CoP of incumbent technology	
AlternateTechEff	: Efficiency/CoP of replaced technology	
TransitionLevel	: Transition option uptake level	
Steepness	: Steepness of transition option uptake path in S-curve	
SaturateYear	: Year which uptake of the transition option saturates	
DiffusionStage	: Diffusion state of the transition option in S-curve, 0≤*DiffusionStage*<12	
R	: Great Britain Government Official Regions,	*i*=11 (all three sectors)
S	: Economic sub-sectors or dwelling types,	*j*=11 (services), 28(industry) or 6(residential)
RS	: Region or sub-sector	
E	: Energy end-use type,	*k*=9 (all three sectors)
F	: Fuel type or dominant incumbent technology in end-use *E* (in fuel switching)	*l* (fuel type)=6 (all three sectors)
F1	: Fuel type or dominant incumbent technology in end-use *E* (in fuel switching), *F* ⊃ *F1*	
TBase	: Base year (year 2010)	
T	: Simulation year	
Tend	: Simulation end year (year 2050)	
a	: Alternative technology set for end-use *E* with fuel *F*	
F→*a*	: Switching from fuel (technology) *F* to alternative technology set (fuels) *a*	
b	: Alternative technology set for end-use *E* with fuel *F1*	
b→*F*	: Switching from alternative technology set (fuels) *b* to fuel (technology) *F*	
m,n	: Number of alternative technologies, *m* & *n* is specific to the fuel type in an end-use	

Disaggregated demand in a simulation year is estimated as in generic Equation (E-1):

$$ED_{R,S,E,F,T} = \sum_{R=1}^{i}\sum_{S=1}^{j}\sum_{E=1}^{k}\sum_{F=1}^{l}\left(\left(\left(\left(\left(EDFrozenTech_{R,S,E,F,T}\right) \pm EDCBehavMngtChange_{R,S,E,F,T}\right) - EDREfficiency_{R,S,E,F,T}\right) - \left(EDRedFuelSwitch_{E,F,T} - EDIncFuelSwitch_{E,F,T}\right)\right) - EDRedReuse_{R,S,E,F,T}\right) - EDRedOnsiteGenUse_{R,E,F,T}\right)$$

(Equation E-1)

EDFrozenTech is the scenario driver driven demand with a technology mix fixed at base year, and is estimated as below:

$$EDFrozenTech_{R,S,E,F,T} = \frac{ED_{RS,E,F,Tbase}}{ScenarioDriver_{R,S,Tbase}} * ScenarioDriver_{R,S,T}$$

(Equation E-2)

Table B-2 lists the scenario drivers in specific end-uses in three economic sectors used in estimation of base year energy intensities and *EDFrozenTech.*

Table B-2 Scenario driver or product of demand drivers used in estimation of base year energy intensity and Frozen Technology demand (*EDFrozenTech)*

Residential Model	
Space heating	Floor area * Household size * Heating Degree Days
Water heating	Population
Lighting	Floor area * Household size
Cooking, Appliances	Household size
Services model	
Cooling & Ventilation	Sub-sectoral GVA * Cooling Degree Days
Space Heating	Sub-sectoral GVA * Heating Degree Days
Computing, Water Heating, Lighting, Other	Sub-sectoral GVA
Industry model	
All end uses	Sub-sectoral GVA

3.1.3. Implementation of transition options

Transition options are applied in the order shown in equation E-1. A demand component in Equation (E-1) is a function of resultant demand from bracketed components preceding it. First, energy management and conservation measures are applied to *EDFrozenTech* at end-use and/or fuel level. Change to internal base temperature from behavioural change is applied by updating simulation year degree days calculated using Hitchin's formula (Hitchin, 1990). Offsets from onsite use of energy productions from onsite solar PV, solar thermal and CHP are applied pro-rate to appropriate end-uses and/or sub-sectors.

In industry, along with end-use specific options across all sub-sectors (e.g. efficient motors, compressed air efficiency), subsector-specific options in Iron & steel and Cement sectors are applied. For all other industrial sub-sectors, sub-sector specific yearly improvements are applied in end-uses where no improvements are applied in earlier steps.

Demand change from fuel switching is estimated first by calculating energy services demand from incumbent technology to be switched from. Technology uptake is modelled in terms of replacement of current end-use fuel demand by incumbent technology with new sets of replaceable alternative technologies. Resulting fuel demand changes are estimates as in Equation E-3 and E-4:

$$EDRedFuelSwitch_{E,F,T} = \sum_{a=1}^{m} EDBeforeSwitch_{E,F,T} * SwitchFraction_{E,F,T,a:F\rightarrow a} * \frac{CurrentTechEff_{E,F,Tbase}}{AlternateTechEff_{a,T}}$$

$$EDIncFuelSwitch_{E,F,T} = \sum_{b=1}^{n} EDBeforeSwitch_{E,F1,T} * SwitchFraction_{E1,F,T,b:b\rightarrow F} * \frac{CurrentTechEff_{E,F1,Tbase}}{AlternateTechEff_{b,T}}$$

(Equation E-3 & E-4)

Transition options are explicitly modelled (forced) with a back-casting approach and is implemented with an exponential uptake curve as follows:

$$TransitionLevel_T = \frac{1}{1 + e^{(-Steepness*Svalue_T)}} * TransitionLevel_{Tend}$$

(Equation E-5)

$$Svalue_T = (-6 + DiffusionStage_{Tbase}) + \frac{(12 - DiffusionStage_{Tbase})}{(SaturateYear - Tbase)} * (T - Tbase)$$

(Equation E-6)

3.1.4. Peak demand calculation

Ref_PL	: National peak electricity demand with a technology mix frozen at base year (reference peak load)
ElecTransportPL	: Changes in national peak electricity demand from transport electrification (G2V & V2G)
ElecHeatPL	: Increase in national peak electricity demand from electrification of heat
DemandResponse	: Aggregate demand response available during peak hours (other than V2G) in fraction of total peak load
DomesticDemand	: Annual electricity demand in residential sector
ServicesDemand	: Annual electricity demand in services sector
TotalSectorDemand	: Total annual electricity demand on the grid
AMR	: Uptake of smart meter (%)
EVPHEVNumber	: Number of EV and PHEV cars
HPDemand	: Electricity demands from heat pumps and electric resistant heating
G2V	: Share (fraction) of cars charging from grid during peak hours
V2G	: Share (fraction) of cars discharging to the grid during peak hours (demand response)

Peak demands of key fuel carries, electricity and gas, are a key metrics for designing and planning energy supply infrastructure that meets demand at all time reliably and cost-effectively. Electricity peak load on the grid is calculated as follows:

$$ElecPL_T = RefPL_T + ElecTransportPL_T + ElecHeatPL_T - DemandResponse_T$$

$$RefPL_T = f(DomesticDemand_T, ServicesDemand_T, TotalSectorDemand_T)$$

$$ElecTransportPL_T = f(RefPL_T, AMR_T, EVPHEVNumber_T, G2V_T, V2G_T,)$$

$$ElecHeatPL_T = f\left(RefPL_{T,}, AMR_T, HPDemand_T\right)$$

(Equation E-7 to E-10)

Ref_PL (reference peak load) is estimated using an empirical method using average annual load[1] and peak load coefficient[2] approach, with the assumption that average annual load correlates with annual generation demand. For UK electricity demand, only residential and services sector demands are assumed to be responsible for peak load coefficient and derived from historical demand data during 1998-2011 (ECUK, 2013; DECC, 2013) – this relationship is assumed to hold good in a business as usual transition.

ElecTransportPL is parameterised using average charging and discharging characteristics where number of EV/PHEVs connected to the grid for G2V or V2G purposes determines the level of stress on the system (Kempton, 2005; IEA, 2011). *ElecTransportPL* model assumes that during peak hours only cars are connected to the grid for G2V and V2G purposes. The assumption is that, all other electric vehicles (such as, buses and HGVs) connect to the grid in non-peak hours for G2V (and V2G) and hence do not alter the peak load regime. Total transport electricity consumption consists of consumption from these vehicles, if any.

For estimating *ElecHeatPL*, the general assumption is that, heat pumps (and electric resistant heating) will be supplying all required heat during peak hours and no back-up systems are used. Peak load change resulting from heat pumps is parameterised with the general assumption that changes in average peak load from heat pumps (and electric resistant heating) is of same order to the difference between average and peak gas demands in past hourly national gas demand data (National Grid, 2013a).

Gas peak load is harder to predict (National Grid, 2013b). We estimated gas peak load with a method similar to electricity reference peak load (*Ref_PL*), where peak load coefficient is empirically derived from past residential sector gas demand in 1998-2010 (ECUK, 2013). This empirical relationship is assumed to hold good into the future.

3.1.5. Simulation step and disaggregation level

Sectoral demand simulation is carried out at yearly time step and results are available by fuel types, end-use, regions and/or sub-sectors, or at any combination of these attributes. Both electricity and gas peak demands are estimated yearly and at national scale. Spatial, seasonal and diurnal disaggregation of peak loads at CGEN+ electricity bus and gas node level are estimated using pre-assigned contribution weights. Seasonal and diurnal weights are based on average historical profiles of electricity and gas demands in 1998-2010 (DECC, 2013). The seasonal and diurnal profiles estimated

[1] Average annual load is [annual demand/ 8760 hours] for electricity and [annual demand/365 days] for gas

[2] Peak load coefficient is the measure of flatness of the load curve

with the above method is empirically adjusted in seasonal and diurnal non-peak values so that total yearly electricity/gas demands derived from respective seasonal and diurnal peak profiles match with total electricity/gas demands from sectoral models. Information on CGEN+ peak demand temporal granularity is described in section 3.3.2.2.

3.2. CGEN+ model

CGEN+ (Combined gas and electricity network model) is an optimisation model for energy infrastructure expansion planning. The model simultaneously minimises energy infrastructure expansion and operational costs. A power generation expansion module determines the type, capacity, location and time that generating plants need to be built in an optimal manner. Network expansion is implemented by adding new assets such as pipes, compressors, and storage facilities in the high pressure gas transmission network and increasing transmission circuit capacity in the high voltage electricity transmission network. CGEN+ is also capable of modelling the distributed production of hydrogen for the use in the transport sector and injection to the gas network.

Resource limitations (economic and materials) and growing energy demand are the main drivers for the need to build optimal energy networks. The model establishes least cost development paths for gas, electricity for given supply and demand scenarios. The optimisation of the expansion planning problem is solved using Fico Xpress solver (Fico, 2009).

3.2.1. CGEN+ components

The CGEN model is comprised of different components. The focus of the modelling is on power generation expansion, gas and electricity transmission network expansion, gas storage, gas interconnector and LNG supplies. CCS-equipped generating units are modelled in CGEN+ through consideration of the additional capital and operational costs of CCS technologies. These units are assumed to be located in the vicinity of the sequestration sites and therefore no additional CO_2 transmission infrastructure is assumed.

Different parts of the infrastructure are arranged into distinct categories, describing energy supply, energy transportation (networks), generation technologies, and end energy use. The flow diagram considered in CGEN+ is shown in Figure B-2.

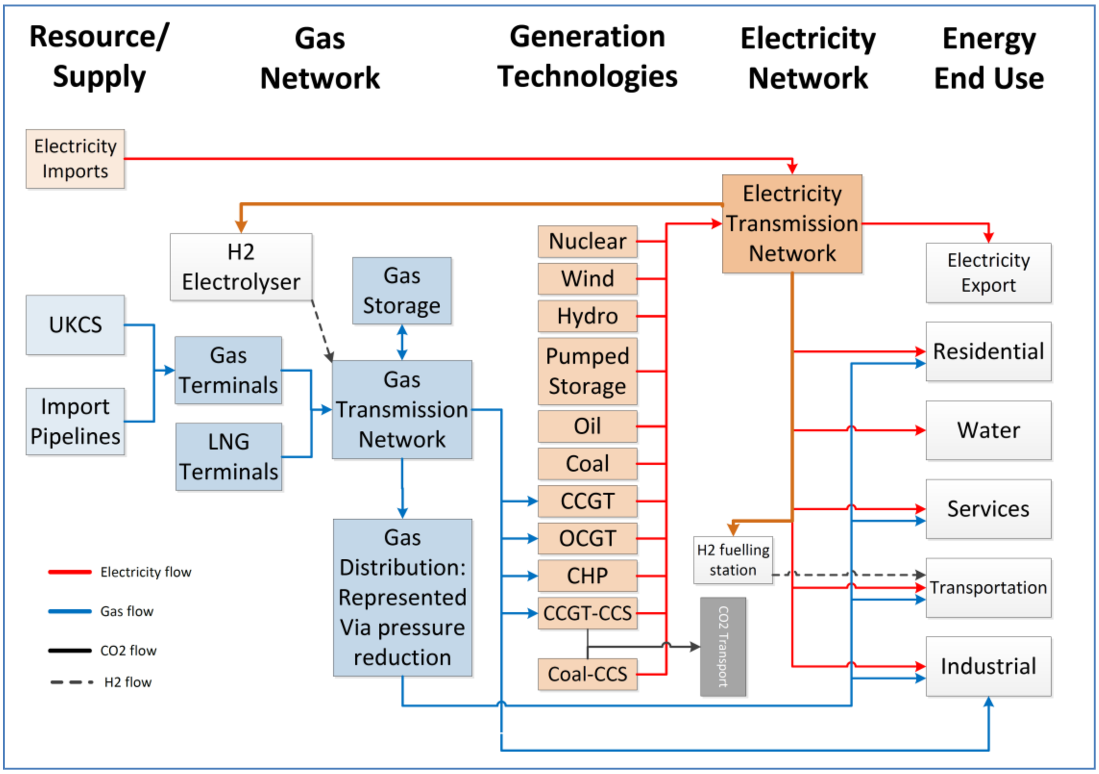


Figure B-2 Flow diagram considered in CGEN+ (Chaudry et al, 2008)

- **Resource/supply:**

This includes bounds (user defined maximum/minimum values applied across operational and planning time steps), such as level of a gas field (bcm) and maximum gas production capacity (mcm/day), or availability of primary energy supplies (gas, coal, oil etc.) and electricity imports. Gas import interconnectors are modelled as gas pipes with maximum transport capacities.

- **Networks:**

The gas network includes the detailed modelling of high pressure transmission pipelines, compressors, gas terminals/interconnections and storage facilities (including salt cavern, depleted reservoir and LNG). The gas flow in a pipe was determined by employing the Panhandle 'A' equation that calculates the gas flow rate given the pressure difference between upstream and downstream nodes (Chaudry et al, 2008).

A DC power flow model was used to represent a simplified high voltage electricity transmission network. The DC power flow formulation enables the calculation of MW power flows in each individual transmission circuit.

Gas turbine generators provide the link between gas and electricity networks. They are considered as energy converters between these two networks. For the gas network, the gas turbine was looked upon as a gas load. The value of the gas load depends on the electrical power flow from the generator. In the electricity network, the gas turbine generator is a source.

- **Generation technologies:**

CGEN+ includes models for all the conventional generation technologies such as CCGT, Coal, and Nuclear. Generation technologies are described by a number of characteristics such as maximum generation and thermal efficiencies.

Renewables such as wind and wave power generation are usually represented by using stochastic models. Use of stochastic modelling would drastically increase simulation solution time and therefore an alternative method of using average load factors that capture regional variations of the UK renewables resource is used.

Average load factors reduce the maximum possible generation from unconventional/renewable plants and are used to capture the variability of generation output.

The decisions on type, capacity, location and time that new generators need to be added to the system are addressed by a generation expansion module and taking into account techno-economic parameters of the technologies such as capital and operational costs, fuel price, service lifetime and CO_2 emission.

- **End energy use:**

Gas and electricity energy demand for five distinct sectors was assumed in CGEN+ (residential, services, industry, transport and water sector). Gas used for electricity generation is calculated endogenously within the model.

3.2.2. Time steps granularity

The CGEN+ network expansion is performed over a planning time horizon (60 years – see Figure B-3). The planning time horizon is comprised of a number of planning time steps (T^E, every 10 years). At each planning time step CGEN+ performs expansion of the gas and electricity infrastructure. Each planning time step is represented by an operational time horizon. The operational time horizon is modelled using operational time steps (*t*) of hours/days to represent seasons and years (the total duration of all operational time steps should equal the value assigned for the planning time step). At each operational time step, gas and electricity operational network constraints (gas flow, pressures, DC load flow etc.) are imposed.

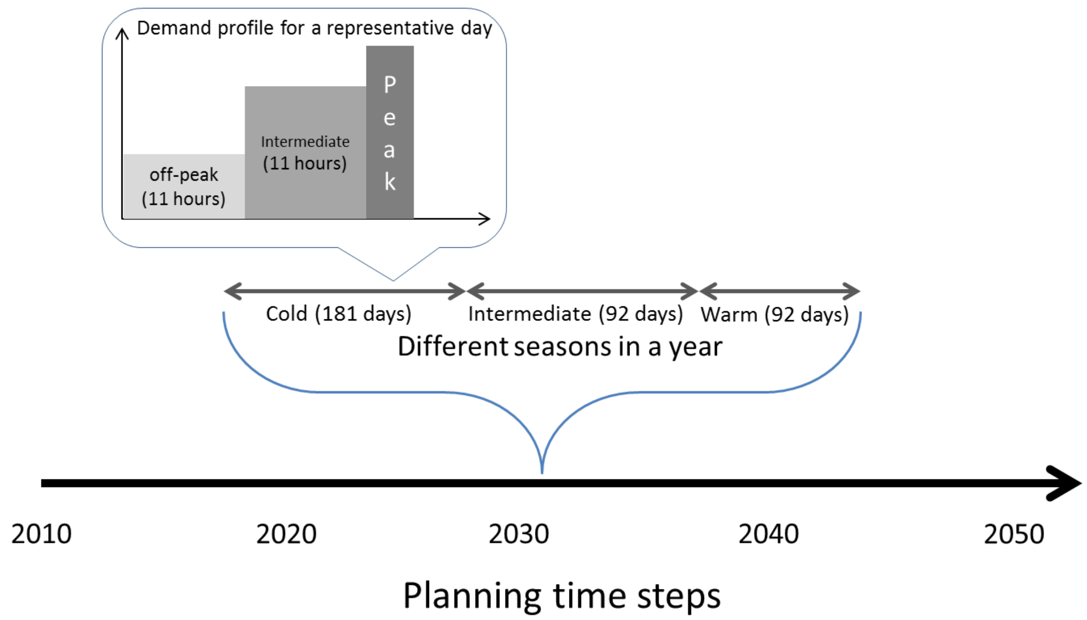
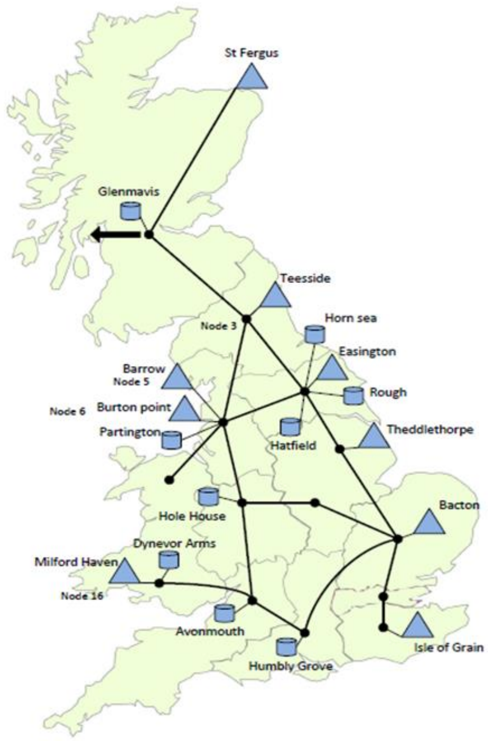


Figure B-3 Planning vs. operational time steps

The CGEN+ planning horizon for modelling the ITRC strategies is 60 years (2010-2059) and the operational time horizon is represented by a typical year divided into seasons (Winter 181 days; Intermediate 92 days; Summer 92 days). Each particular day of a season is represented by a peak of 2 hours, off-peak period of 11 hours and intermediate period of 11 hours.

3.2.3. Spatial granularity

A simplified gas network, shown in Figure , was used to represent the cross-region gas flow capacity of the GB National Transmission System (NTS). A sixteen busbar electricity network was used to represent the GB high voltage transmission network (see Figure B-5).



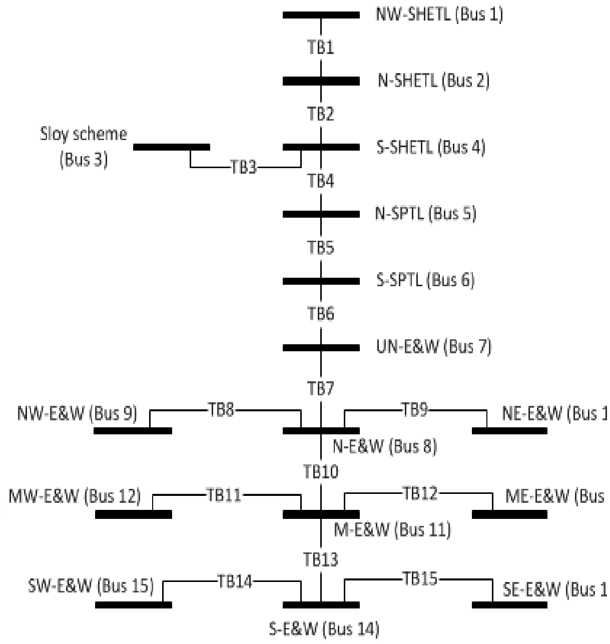


Figure B-4 A simplified gas network for GB (2010)

Figure B-5. A simplified electricity network for GB

3.2.4. Objective function of the CGEN+ model

The objective function of the CGEN+ is comprised of investment costs of the new infrastructure and operational costs of the system. At each planning time step, CGEN+ decides upon the expansion of the gas and electricity infrastructure.

All costs are represented as their present value equivalents. The time value of money was modelled using a discounted cash flow approach:

$$Present\ value = \frac{Future\ value}{(1+r)^n} \qquad \text{(Equation E-11)}$$

Where, *r* is the discount rate and *n* is time difference in years between present and the future planning time step. A discount rate of 3% was used for investments on network expansions (UK government's discount rate for regulated assets). For all other investments (e.g. power station) a discount rate of 10% was used (typical rate used for commercial investments). An annual equivalent approach was employed to represent expansion planning capital costs. The annual equivalent of a lump sum unit investment cost was obtained by replacing this lump sum by a stream of equal annual payments over the life of the equipment (this allows capital costs to be compared on an annualised basis).

The objective function (E-12) is subject to operational network constraints of both gas and electricity networks:

$$\min Z = \sum_{t} \frac{1}{(1+r)^t} \left(\underbrace{\substack{capital\ cost\ of \\ new\ infrastructure}} + \underbrace{\substack{operating\ cost \\ of\ the\ systems}} + \underbrace{\substack{cost\ of \\ unserved\ energy}} \right)$$

(Equation E-12)

Where, *t* is planning time steps.

3.2.5. Infrastructure expansion planning

For both gas and electricity networks, CGEN+ adds transmission capacity to satisfy peak demand requirements. Figure illustrates how the optimisation routine within CGEN+ explores all possible solutions to satisfy peak demand. This ranges from building additional network capacity to the re-dispatching of energy (e.g. substituting cheaper gas from Scotland with expensive gas from LNG terminals in the south of England in order to bypass transmission bottlenecks); the model will select the cheapest solution over the entire time horizon.

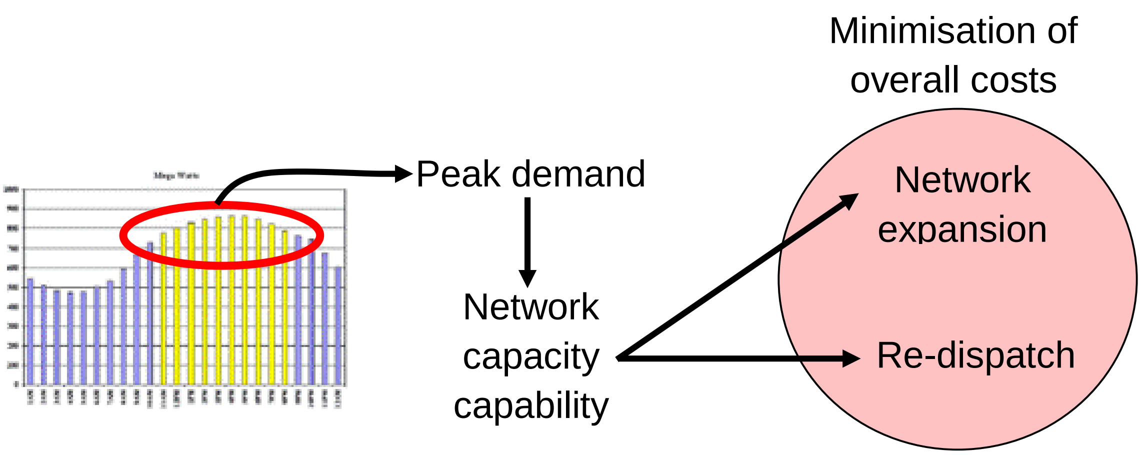


Figure B-6 Network infrastructure expansion

The 1 in 20 peak day (National Grid employs this standard to expand its gas network) gas supply standard and the average cold spell electricity demand are enforced in the model. CGEN builds supply infrastructure to satisfy both requirements.

- **Gas network planning and operation model**

The gas network assets that are reinforced in the model over the planning period are gas pipes, compressor capability, LNG terminal capacity, import pipeline capacity, and gas storage facilities. Gas network planning optimisation will simultaneously satisfy operational and planning constraints. Detailed formulation for gas network planning and operation can be found in Chaudry et al (2014).

- **Power system planning and operation model**

Power generation and transmission network expansions take place through adding new generators at each busbar and increasing transmission capacity between buses, respectively. DC power flow equations were used to analyse the electricity network (Wood and Wollenberg, 1996). Detailed formulation for power system planning and operation can be found in Chaudry et al (2014).

3.2.6. Modelling energy infrastructure security of supply

Table B-3 shows the constraints that are enforced in the CGEN+ model to ensure security of supply and the outputs that can be used to measure supply security of energy infrastructure.

Table B-3 Security of supply CGEN+ input constraints and model outputs

Model inputs/constraints
▪ Availability of different generation technologies
▪ Derated capacity margin was assumed to be greater or equal to the Average Cold Spell (ACS) for electricity peak
▪ Maximum gas supply capacity (from terminals and storage facilities) was assumed to be greater or equal to the 1 in 20 gas peak demand
Outputs of the model
▪ Generation capacity margin
▪ New capacity of LNG ▪ New gas interconnectors ▪ New gas storage facilities

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