TECHNO-ECONOMIC ASSESSMENT OF SMART GRID SOLUTIONS IN THE RUSSIAN DISTRIBUTION NETWORK OF BASHKIRENERGO

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ABSTRACT

Bashkirenergo and Siemens PTI recently completed a comprehensive study on suitable modernization and renovation steps of the Ufa electricity network, Bashkortostan republic in Russia.

In this joint project, an optimal set of innovative concepts and technologies was developed and further used to create a technically and economically feasible masterplan, which addresses the following main targets: modernization and enhancement of the grid structure, reduction of losses, improvement of security of supply and reduced operation expenditures.

Four different scenarios regarding network structure and automation concept were developed and assessed in order to identify the most efficient solutions. Finally, the selected measures were prioritized and compiled into a transition plan starting from today up to the year 2020.

INTRODUCTION

Presently, transmission and distribution network operators in Russia face several technical challenges, which have to be addressed to achieve a sustainable future development. In this context, Joint Stock Company Bashkirian Power Grid Company (Bashkirenergo), the major owner of Ufa city network, defined the following development targets:

- Increased security and quality of power supply
- Economic efficiency of integration of new and innovative technologies
- Decrease of power losses

Due to the fact that Bashkirenergo is a privately owned company, for all intended network development measures both technical and economical feasibility of each individual technology has to be investigated and proven.

This paper summarizes different steps of a development project for the Bashkirenergo sub-transmission and distribution network to answer the following questions:

- How is the situation of the network infrastructure today?
- What are the critical issues, which have to be solved?
- Which technical solutions can be implemented to solve existing and future problems and which of these measures are also economically feasible?
- How does the roadmap for implementation of the solutions until 2020 look like?

SITUATION IN UFA TODAY

Introduction to Bashkirenergo

The network owned by Bashkirenergo comprises the voltage levels 110 kV, 35 kV, 10 kV, 6 kV and 0.4 kV. The project, which is described in the following, was done for the Ufa city – capital of the Bashkortostan Republic. Ufa, a large industrial city with a population of more than one million inhabitants, is the capital of the Republic of Bashkortostan, part of the Volga Federal District. Ufa's electricity supply is carried out by electricity networks of several voltage levels: 110-35-10-6-0.4kV. Supply centers are 110kV or 35kV substations. The distribution network of 6-10kV network is mainly a simple radial scheme, based on underground cables. Ufa's 6-10kV, 0.4kV electricity grid management is geographically divided into seven regions. Operational monitoring of power parameters (power, currents, voltage levels) and of switch positions at substations are partly implemented with an operational information complex (OIK - Dispatcher) in real-time. The current level of remote control allows control and forecast of technological regimes for the 6-10kV network at substations only (feeding centers). But the remote control and automation does not exist in 6-10/0.4kV transformation stations, affecting the quality of normal or maintenance regime management, leading to increased time for localization and liquidation of 6-10/0.4kV networks outages and, as a result, to increased unsupplied electricity [1].

Analysis of today's and future challenges

After the comprehensive data collection process, the overall HV and MV network was modeled for 2013 state (winter and summer load-flow scenarios) in the network analysis and simulation software PSS®SINCAL. Then, a detailed evaluation of the technical performance of the network was carried out with help of load-flow, short-circuit and reliability calculations. The main challenges of the existing network (see Fig. 1) are a rather complex and historically grown network structure with partly inefficient supply paths, several long feeders, missing redundancies and aging equipment, which will necessitate major investments in new network equipment in the near future.

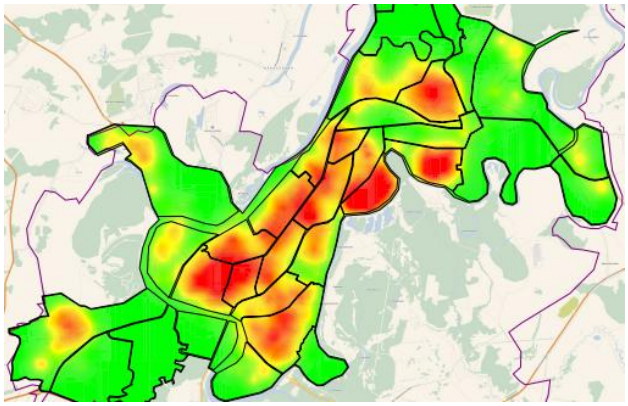


Figure 1: Overview over the Bashkirenergo network including the load distribution for the peak load case

The overall network performance is currently sufficient, although the supply reliability cannot meet European level and shall be improved (229 minutes vs. 114 minutes as average annual interruption time in European network [2]). The electricity energy losses in Ufa are at 15.6%, suggesting a significant potential for reduction. Furthermore, an expected load increase of 3 % per year will result in a total load growth of about 20 % in 2020. The present level of automation is very low and locally restricted with very limited communication infrastructure in the MV network. Functionality and potential of the SCADA system is limited due to improper field equipment. A high diversity of protection devices, which are partly based on mechanical relays technology, is planned to be updated and integrated into a new automation system.

TECHNOLOGICAL SOLUTIONS FOR IMPROVED NETWORK DEVELOPMENT

Main targets for future network performance

After the analysis of present network performance, different criteria and targets for the future network were defined. As a result, four different scenarios were developed which differ with respect to voltage level and topology, automation level, improvement of reliability performance and reduction of commercial losses:

- Scenario 0: Base scenario, minimum changes and automation
- Scenario 1: Minimum changes in topology with high level of automation
- Scenario 2: Optimization of network topology including high level of automation
- Scenario 3: Topology optimization and voltage upgrade to 10 kV with maximum level of automation

Optionally Smart Metering solutions can be added. These scenarios were investigated in detail using the approach described further in the paper.

Characteristics of developed scenarios

In a first step, suitable standard components for cables, switchgear and transformers were defined. Then, adequate network structures were developed in a way that grid code requirements and scenario-specific targets are met. Fig. 2 shows an example configuration being valid for Scenario 2 (left) and Scenario 3 (right).

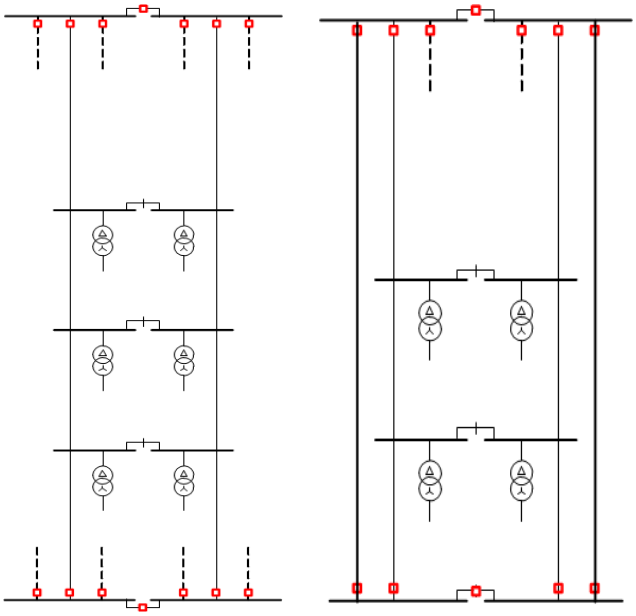


Figure 2: Network structure for Scenario 2 and Scenario 3

Table 1 gives a detailed overview of the automation solutions used in the developed concepts. Scenario 0 and Scenario 1 use the present topology but different measures for automation, monitoring and metering. Scenario 2 and Scenario 3 further include optimization of the network structure with different level of automation and smart grid technologies. For each scenario a bill of quantities of primary and secondary level equipment was created.

ANALYSIS OF TECHNICAL PERFORMANCE OF SELECTED TECHNOLOGIES

Scenario 0 considers conventional fault indicators and analogue ammeters. This approach requires least investment, but still provides basic system observability that increases system security and reliability. Most European networks have similar degree of automation [3,4]. Main features of Scenario 1 and 2 are:

- Usage of Feeder Condition Monitor (FCM) devices for the purpose of high-level observability
- Upgrade of the existing control system
- Usage of the digital protection system
- Measurement of power quality from the MV feeders and LV transformer side
- Establishment of communication at the MV network level.

Table 1: Overview of automation concepts

Network Automation			
Criteria	Target Values		
	Scenario 0	Scenario 1/2	Scenario 3
Switch Operation	Manually – by crew Remote Control where available	Sectionalizing (normal open) switch-disconnectors are telemetered / controlled remotely	MV grid: Automatic remote control HV grid: Remote Control – All CBs equipped with reclosers
Protection	Existing Protection Devices	Digital Protection	Digital Protection
Fault Indication	Overcurrent and Earth Fault Indicators – inspected by crew (no telemetering)	Feeder Condition Monitor (FCM) devices – provide accurate fault location, the information is telemetered to control centers	FCMs – provide accurate fault location. Digital Fault Recorder devices at strategically important network points – fault cause and fault development analysis. Power quality monitoring directly from the control center
Fault Localization	Manually – by crew	Fault location automatically determined from the control center	Fast Automatic Fault Location Determination
Fault Isolation	Manually – by crew	Remotely from control center via disconnectors and manually by crew	Closed loop control – network automatically recognizes and isolates the fault
Service Restoration	Manually – by crew	Remotely from control center via disconnectors and manually by crew	Closed-loop control – after fault isolation, the supply is restored automatically to the affected loads
Fault Record Tracking / Fault Prediction	n.a.	Outage Management System	Outage Management System
SCADA	Existing SCADA system installed in distribution control centers – provides limited supervision without control	SCADA system installed in distribution control centers – provides limited visibility and control.	SCADA system installed in distribution control centers – full visibility and automated control.
EMS	n.a.	Network Analysis (NA) applications: Load Forecasting, Power Flow, State Estimation, Short-Circuit Analysis	The complete Advanced Network Analysis (ANA) suite: Power Flow, State Estimation, Short-Circuit Analysis, Volt-Var Control, Optimal Feeder Reconfiguration, Load

In addition to the automation and control concept used for Scenario 1/2, Scenario 3 considers maximum automation level including intelligent transformer stations with regulated transformers, RTUs and communication via fiber optics [5].

As an example of the results the reliability performance of each scenario is illustrated in Fig. 4.

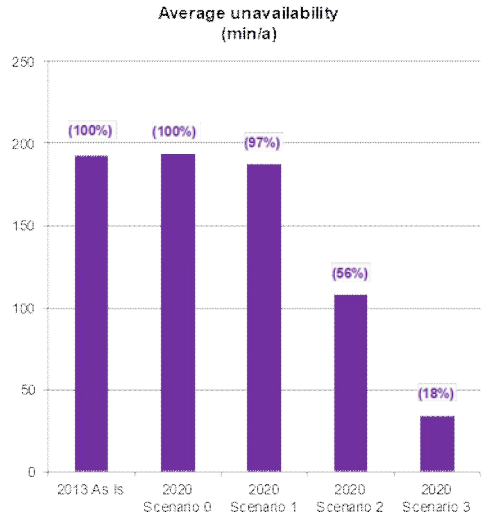


Figure 4: Average unavailability (min/a)

Reliability performance of present network and Scenarios 0 and 1 are virtually identical as these have the same network structure. Unavailability of Scenario 1 is slightly lower due to a number of automated stations. For Scenario 2 there is a significant improvement visible due to elimination of T-offs and interlinks and increase of redundancies, better allocation of stations to feeders, optimization of location of open points and reduction of size of tripping areas. Scenario 3 shows lowest unavailability due to optimized network structure and maximum level of automation.

ANALYSIS OF TECHNO-ECONOMIC EFFICIENCY OF MEASURES

For each technology a techno-economical evaluation was performed, including the assessment of capital and operational expenditures, technical and commercial losses,

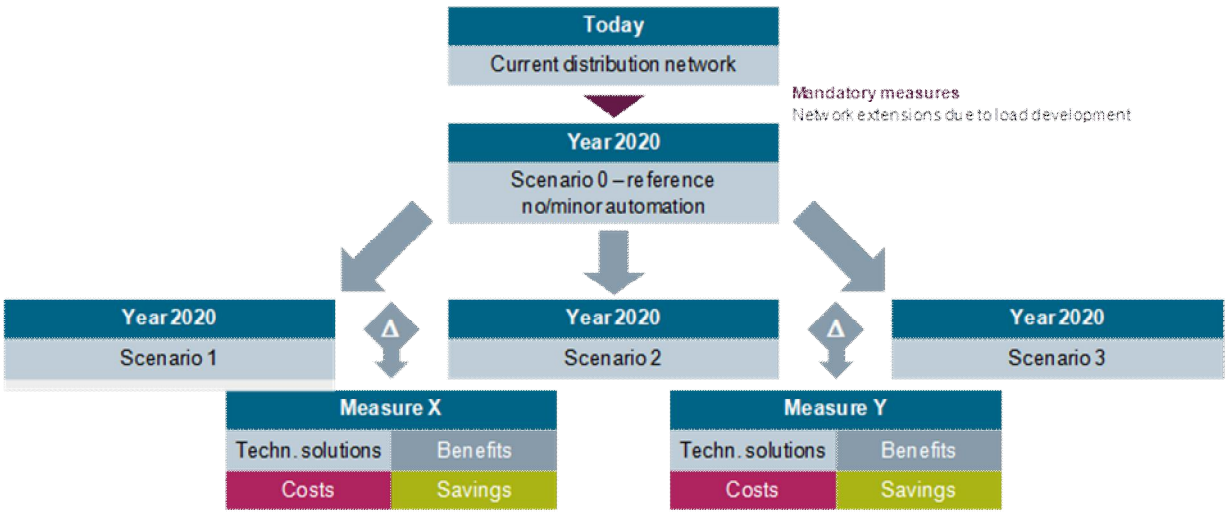


Figure 3: Methodology for assessing improvement measures

as well as the calculation of net present value and return of investment. Using the described scenarios and the assessment approach shown in Fig. 3, individual measures could be identified and evaluated.
Table 2 contains an overview on the analysis of all seven measures, which have been extracted during the analysis. The following selected measures were found to provide significant benefits while ensuring a positive return of invest after max. 10 years:

Measure 1: Optimized network topology using GIS switchgear

- quick understanding of power flow and operating-structure
- reduced necessity for strong multiple feeding routes; can safe operational network planning investment costs
- faster response to disturbances by faster system analytics and faster decision making on network re-configuration
- reduction of technical losses
- reduction of customer minutes lost and energy not supplied
- reduction of loading and overloading
- maintenance-free GIS switchgear over lifetime
- reduction of required staff for asset management and maintenance
- higher reliability of GIS compared to modern AIS (air insulated switchgear)
- high safety standard of GIS for operating staff
- reduced space requirements of GIS

Measure 3: High automation level

- better monitoring of power flow and operating-structure
  - avoid overloading by early recognition of highly loaded assets
  - avoid outages
  - reduce necessity for strong feeding routes
  - safe operational network planning investment costs
- faster response to disturbances by faster system analytics and faster decision making on network re-configuration
- reduction of technical losses
- reduction of customer minutes lost and energy not supplied
- reduction of loading and overloading
- observability of power quality extends asset lifetime and avoids damage of end-customers devices/assets/property

Measure 6: Smart metering

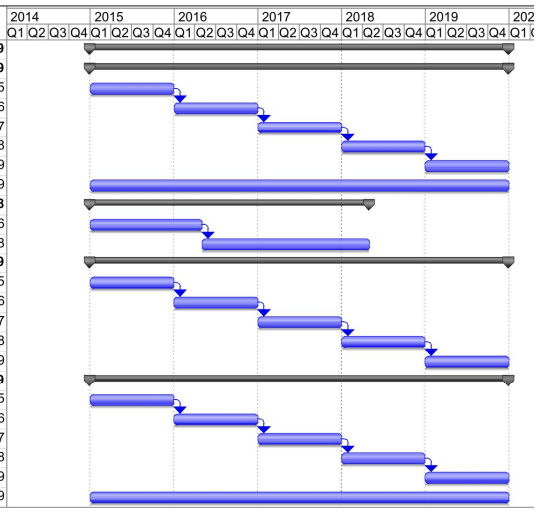
- remotely readable energy consumption
- remote meter reading without OPEX for reading
- detection of energy leakage
- decrease commercial losses identification
- Remote reading of measurement values as current, voltage, frequency, active and reactive power
- monitoring of power quality possible
- recording of load profiles for, which can be read remotely to achieve better customer load profiles
- optimization of energy production/balance, more accuracy in balance
- peak shaving possible with adequate customer participation
- reduction of peak loading
- avoidance of necessary operational network

Table 2: Summary of technical and economical analysis

Measure	Description	Reliability	OPEX reduction	Technical losses	Non-tech. losses	Return of invest
1	**Optimization** of network structure	✓	✓	✓		✓
2	Network **voltage upgrade**			✓		✗
3	Introduction of basic **network automation**	✓	✓			✓
4	**Optimization** of structure + network **automation**	✓	✓	✓		✓
5	Network **voltage upgrade + High-end automation**	✓	✓	✓		✗
6	**Smart Metering**				✓	✓
7	**0.4kV network re-structuring**		✓	✓	✓	✓

Figure 5: Implementation Plan of Smart Grid Roadmap

Nr.	Task Name	Dauer	Anfang	Ende
1	**Modernization of Ufa electrical grid complex**	**1307 Tage**	**Do 01.01.15**	**Di 31.12.19**
2	**Reconstruction and automation (observility and remote control) 517 DS and TS**	**1307 Tage**	**Do 01.01.15**	**Di 31.12.19**
3	Reconstruction and automation of 50 DS and TS	261 Tage	Do 01.01.15	Do 31.12.15
4	Reconstruction and automation of 100 DS and TS	261 Tage	Mo 04.01.16	Sa 31.12.16
5	Reconstruction and automation of 110 DS and TS	262 Tage	So 01.01.17	So 31.12.17
6	Reconstruction and automation of 126 DS and TS	261 Tage	Mo 01.01.18	Mo 31.12.18
7	Reconstruction and automation of 131DS and TS	261 Tage	Di 01.01.19	Di 31.12.19
8	Integration of DS and TS into SCADA	1307 Tage	Do 01.01.15	Di 31.12.19
9	**SCADA integration**	**874 Tage**	**Do 01.01.15**	**Do 03.05.18**
10	SCADA installation and comissioning	348 Tage	Do 01.01.15	Mo 02.05.16
11	Related systems integration with SCADA	526 Tage	Di 03.05.16	Do 03.05.18
12	**Network structure optimization (laying of 462 km of cables)**	**1307 Tage**	**Do 01.01.15**	**Di 31.12.19**
13	Laying of 29 km of cables	261 Tage	Do 01.01.15	Do 31.12.15
14	Laying of 79 km of cables	262 Tage	Fr 01.01.16	Sa 31.12.16
15	Laying of 100 km of cables	262 Tage	So 01.01.17	So 31.12.17
16	Laying of 125 km of cables	261 Tage	Mo 01.01.18	Mo 31.12.18
17	Laying of 128,5 km of cables	261 Tage	Di 01.01.19	Di 31.12.19
18	**Smart meters installation**	**1307 Tage**	**Do 01.01.15**	**Di 31.12.19**
19	8000 meters installation	261 Tage	Do 01.01.15	Do 31.12.15
20	16000 meters installation	262 Tage	Fr 01.01.16	Sa 31.12.16
21	16000 meters installation	262 Tage	So 01.01.17	So 31.12.17
22	20000 meters installation	261 Tage	Mo 01.01.18	Mo 31.12.18
23	20000 meters installation	261 Tage	Di 01.01.19	Di 31.12.19
24	Integration of meters into MDM system	1307 Tage	Do 01.01.15	Di 31.12.19



NETWORK TRANSITION PLAN

In a final step of the study a detailed roadmap of the transition actions was created considering enhancement of network structure and installation of FCM, RTU, additional SCADA functionalities and smart metering technology.

The example of the transition plan can be seen in Fig, 5. Based on this plan, the power grid company approved the investment program and proceeded to the stage of implementation of the comprehensive urban electricity grid modernization project. Roadmap was developed till year 2020 and consists of replacement of main equipment, secondary equipment, SCADA system installation and metering system deployment.

CONCLUSION

The assessments showed that optimization of network structure using existing 6 kV and 10 kV equipment and GIS technology as well as network automation using feeder condition monitoring, digital power meters and partially remote-control of transformer stations lead to a positive return of investment after 10 years.

Due to the fact that applying all mentioned measures (which is reflected in Scenario 2) would still be economically attractive, it was recommended to realize Scenario 2 as the techno-economical optimum solution.

Benefits of the measures corresponding to Scenario 2 are:

- Significant reduction of technical losses (up to 30%), mainly due to network optimization
- Reduction of operational cost due to maintenance free GIS distribution stations (minus 20%)
- Implementation of automation increases reliability (approx. plus 80%) and decreases operational cost (switching, maintenance, etc.)
- Almost complete reduction of commercial losses due to installation of smart meter (minus 90%)

At the moment the project is in the implementation phase – the pilot area will be ready in May 2015. The pilot area consists of 2 distribution stations and 5 transformer stations. Also control center is under development and will be finalized in 2015.

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