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Description

[0001] The present invention relates to a method for monitoring aging processes of insulation in high-voltage devices, and to an associated high-voltage device.

[0002] DE 102009007142 A1 describes an optical fiber measuring device for detecting load conditions of low-voltage and medium-voltage cables, in particular of power cables of refrigerated containers and offshore wind power plants. This optical fiber measuring device has a number of sensors which are integrated into the cables and can detect a mechanical loading of the cable, or of the fiber, in particular by a bend, or distribution, a temperature, and/or cursive gases. The sensors are fed light from an external source and form an optical fiber sensor network. Further prior art is described in US/2005/134837 A1.

[0003] Failures occur repeatedly in electrical plants for supplying energy due to damaging influences on the high-voltage device and signs of aging of the insulation. These failures are mainly caused by partial discharges. During the partial discharges, so-called partial discharge trees are formed, which grow over time and ultimately lead to an electrical breakdown if the affected plants are not switched off in good time. Therefore, partial discharges in insulation of cable fittings, such as terminations and cable sleeves for high-voltage-current cables, or high-voltage cables, at an advanced stage can lead to total destruction of the cable fittings. Due to the high energy release associated with the breakdown, further parts of the plants can be damaged in the process. Therefore, the damage caused by such rather rare events can be considerable. As such, there is a need to reliably detect and evaluate signs of aging or partial discharges in insulation of high-voltage devices during ongoing operation if possible.

[0004] A previously established method consists of measuring electrical current pulses and/or electromagnetic signals associated with the occurrence of partial discharges. However, the interpretation of such measurement results is often difficult under practical conditions because of electromagnetic interferences. Such measurements are also very complex and typically require the setup of suitable measuring and testing systems on site. As such, monitoring typically takes place only at longer time intervals or if emerging damages are suspected. In addition, the measuring sensitivity of electromagnetic environmental disturbances is limited, such that partial discharges are detected only at a late stage; that is, shortly prior to the breakdown. This is because electromagnetic measurements can only be carried out in safe access areas; this is, outside the high-voltage area. Due to the greater distance to the location of the partial discharge, only partial discharges from a specific intensity can therefore be detected.

[0005] In addition, the damage to the insulation, which typically precedes a partial discharge, cannot be detected with such electrical or electromagnetic measurements. However, this would often be desirable for predicting the fatigue or aging status of the insulation.

[0006] According to common understanding, a polymeric insulating material in the high-voltage alternating field changes in a plurality of stages. This is typically based on a three-stage phenomenological polymeric insulation aging model, which includes the partial discharge process as a third stage. Charge carriers which, depending on the material and field distribution, are characterized by a characteristic critical field strength are provided in the first stage. This process can proceed in the insulating material volume wherever the critical field strength is exceeded as a result of, for example, production-related inhomogeneities. However, it can also take place at the interface to the current-carrying conductor. The second model stage is characterized in that an energy transfer from the electric field via the injected charge carriers to the polymer matrix takes place at the beginning of the charge carrier injection. Material-dependent and production-related inhomogeneities play a central role here, since they serve as starting points of the irreversible damage mechanisms now starting. The charge carrier injection in the respective half-oscillations of the high-voltage alternating field results in a space charge buildup at adhesion points. This can result in electroluminescent events. The occurrence of electroluminescence in this phase can be caused by so-called "hot electron" processes, by excitation of molecules, and by charge carrier recombinations. Which of these processes may dominate depends on the material. The energy transfer via the injected charge carriers leads to irreversible chemical, mechanical, and thermal changes of the polymer structure. In the process, the local field strength curve is typically greatly influenced by space charge reactions. This may result in the subsequent formation of microcavities, in which partial discharges ignite after a critical magnitude is exceeded, with the result that the third stage is reached.

[0007] In the further course, increasingly stronger partial discharges can then occur, which can lead to growing partial discharge trees and ultimately to undesirable electrical breakdown.

[0008] In light of the aforesaid, the present invention proposes a method according to claim 1 and a high-voltage device according to claim 9.

[0009] According to one embodiment, a method for monitoring aging processes of insulation in a high-voltage device is provided. The method comprises the step of measuring a light signal generated in the insulation with a first optical fiber sensor and the step of measuring a mechanical variable of the insulation with a second optical fiber sensor. For this purpose, the insulation comprises at least one transparent or translucent subregion, into which the first optical fiber sensor is at least partially embedded and/or on the surface of which the first optical fiber sensor is at least partially arranged. The terms "transparency" and "translucency" refer to expected wavelengths and/or wavelength ranges of the light signal generated in the insulation. The light signal generated in the insulation may be, for example, an electroluminescent event, for example, in the near infrared range up to the visible wavelength range but also a light phenomenon generated by a partial discharge, for example, in the visible light range up to the UV range. Typically, the transparent or translucent subregion has a sufficiently low absorption coefficient for detection for at least one wavelength from the expected electroluminescence spectrum and/or for at least one wavelength from the expected optical spectrum of a partial discharge. The term "measurement of a light signal generated in the insulation" as used herein is to be understood in particular as a measurement of an optical variable which represents a measure for the occurrence of an electroluminescent event and/or a discharge event in the insulation in the high-voltage field. The measurement of a mechanical variable typically provides a measure for a partial discharge occurring in the insulation. However, it may also provide a measure for a change preceding a partial discharge, for example, for a setting phenomenon in the insulation. An estimation of an aging status of the insulation is also carried out. This enables simple, and/or fault-tolerant, and/or very sensitive monitoring of the aging status of the insulation.

[0010] As used herein, the term "high voltage" is to include voltages above approximately 1 kV; in particular, the term "high voltage" is to include the nominal voltage ranges customary in energy transmission of medium voltage of approximately 3 kV to approximately 50 kV, of high voltage of approximately 50 kV to approximately 110 kV, and maximum voltages up to currently approximately 500 kV. If the cable operating voltages are further increased, such voltage ranges are also to be included. These may be both direct voltages and alternating voltages. The term "high-voltage cable" as used herein is to describe a cable that is suitable for conducting high-voltage current; that is, electrical current of more than approximately one ampere at voltages above approximately 1 kV. Hereinafter, the terms "high-voltage cable" and "high-voltage-current cable" are used synonymously. Accordingly, the term "high-voltage device" or "high-voltage cable fitting" is to describe a device which is suitable for connecting high-voltage plants and/or high-voltage cables to one another.

[0011] As used herein, the term "partial discharge" is to describe short-term, low-energy, and locally limited discharges in the insulation that do not immediately result in electrical breakdown, but irreversibly damage the material of the insulation. The term "partial discharge" is to include, in particular, the term "internal partial discharge,"; that is, a discharge event in non-gaseous insulating materials, in particular in solid insulating materials, which is not necessarily visible externally. Starting from defects, such as cavities, and foreign inclusions, or interfaces to other materials, in particular to high-voltage-carrying conductors, partial discharges lead to partial discharge trees which grow over time in the insulating material, which may ultimately lead to breakdown. Partial discharge trees typically have a size of greater than approximately 1 μm (microns).

[0012] The apparent charge which can be measured directly at the test terminals of an electrical measuring arrangement can be used as a measure of the strength of a partial discharge. With established electrical and electromagnetic measuring methods, partial discharges with an apparent charge of more than approximately 1 pC can currently be detected under test conditions customary in practice. Industry standard IEC 60840 Ed. 3, 2004-04 requires a measuring accuracy of approximately 5 pC for testing high-voltage plants. During high-voltage operation of the high-voltage device, however, the measuring sensitivity of such methods is limited by fundamental electromagnetic interference levels to a range from approximately 20 pC to approximately 50 pC. The term "partial discharge" as used herein is to include, in particular, discharges in the insulation with apparent charges, that is, electrically measurable apparent charges, of more than approximately 1 pC. The term "partial discharge" as used herein, however, is also to include so-called "pulse-free partial discharges," which are currently detectable with the established electrical and electromagnetic measuring methods on samples under laboratory conditions, but not on technical systems, such as high-voltage devices.

[0013] Partial discharges can be distinguished from electroluminescent events in the high-voltage field by their highly stochastic discharge behavior, the growth of the partial discharge trees even at a constant field strength, and, depending on the insulation material and field strength, by a possibly deviating frequency spectrum, and/or the typically different light intensity. The light intensity of electroluminescent events of insulating materials is typically weaker in the high-voltage field at the same electric field strength than the light intensity of a partial discharge, in particular for partial discharges with apparent charges of more than approximately 1 pC. Moreover, the electroluminescence is typically characterized by reproducible intensity values at the same field strengths, the intensity being nearly independent of the history.

[0014] According to an additional form, the measurement of a light signal generated in the insulation comprises a measurement of a light intensity, a light wavelength, and/or a pulse duration of an electroluminescent event occurring in a field control part of the insulation, and/or a discharge event occurring in the field control part with an apparent charge of less than approximately 5 pC, less than approximately 2 pC, and even less than approximately 1 pC. Thus, electroluminescent events and/or discharge events which cannot be detected with the measuring accuracy required by the industry standard IEC 60840 for discharge events can also be detected. Early aging statuses of the insulation can thus be monitored by measuring a light signal generated in the insulation. This allows a substantially earlier and/or more accurate estimation of the aging status of the insulation.

[0015] However, the measurement of a light signal generated in the insulation can also comprise the measurement of a partial discharge event; that is, of discharge events with an apparent charge of more than approximately 5 pC. This enables a simple detection of partial discharge processes and thus of a more advanced aging status of the insulation.

[0016] Depending on the intensity, partial discharges are also associated with short sound emissions in the range of approximately 10 kHz up to approximately several hundred kHz, which can be detected by the second optical fiber sensor. As a result of electrochemical changes (reaction decrease) and/or during partial discharges, mechanical stresses can furthermore develop, and cracks and gaps can consequently form in the insulating material. The measurement of a mechanical variable typically comprises the measurement of a change in a mechanical property of the insulation and/or an oscillation occurring in the insulation. The mechanical variable of the insulation may be an expansion of the insulation, a density of the insulation, a pressure or a mechanical stress in the insulation, a deformation of the insulation, a variable characterizing a mechanical oscillation of the insulation, and/or a variable which characterizes a mechanical wave, that is, an acoustic wave, propagating in the insulation and/or originating from the insulation. The mechanical variable may comprise, in particular, an acoustic frequency, an acoustic pressure level, an acoustic duration, and/or an acoustic intensity of an acoustic event generated in the insulation of electrical partial discharges. This enables a simple detection of partial discharge processes and thus of a more advanced aging state of the insulation.

[0017] Through the use of the first optical fiber sensor and the second optical fiber sensor, changes in the insulation from an early stage up to partial discharges can be detected without expensive external measurement setups. Optical fiber sensors can be designed to be highly sensitive, on the one hand, and can be made from only dielectric materials, on the other hand, such that they can in principle be used in the high-voltage field, that is, near regions susceptible to partial discharges, or even in regions susceptible to partial discharges without significantly changing the high-voltage field. This also allows a simple continuous monitoring of the state of the insulation during the operation of the high-voltage device, for example, by transmitting the measurement results to a central evaluation unit. Thus, an imminent breakdown in the high-voltage device can be detected early, the plant can be switched off, and consequential damage can be avoided by replacing the aged insulation or the complete high-voltage device.

[0018] In particular, the method can be used for monitoring aging processes of the insulation of a high-voltage cable fitting, for example, a cable sleeve or a cable termination. The insulation in cable sleeves and cable terminations is typically exposed to high electric field strengths in particular in the vicinity of conductor ends and/or in the vicinity of openings in the cable insulation. Therefore, monitoring aging processes in such devices can particularly contribute to increasing operational reliability.

[0019] In addition to individual measurements of a mechanical variable and/or individual measurements of a light signal generated in the insulation, their temporal development can also be included in the estimation of the aging status of the insulation. Improved prediction accuracy can thus be achieved.

[0020] In the detection of an acoustic event in the insulation, the acoustic pressure, and/or an acoustic frequency, and/or the acoustic duration are typically taken into account for estimating the aging status of the insulation. Such values can be easily determined and are well-suited for characterizing partial discharges.

[0021] In an analogous manner, when detecting a light signal in the insulation, its integral light intensity and/or a measure for the fluctuation of the light intensity is typically taken into account for estimating the aging status of the insulation. Such values can likewise be determined in a simple manner, and are well-suited for characterizing partial discharges and electroluminescent events, or for distinguishing them.

[0022] However, it is also possible to use variables that are more complex to determine, such as the length of a partial discharge tree, in the insulation, in order to estimate the aging status of the insulation. Data from a plurality of first, and/or second optical fiber sensors are required for this purpose. In return, however, the length of a partial discharge tree is a particularly relevant parameter for characterizing a more advanced aging status of the insulation.

[0023] According to an additional form, an aging status of the insulation is estimated in a central evaluation unit. The central evaluation unit typically monitors a plurality of insulation materials, for example, all insulation materials in cable sleeves and cable terminations of a high-voltage device, for example, a voltage network.

[0024] According to yet another additional form, a warning message or a warning signal is output if the aging status of the insulation exceeds a specified threshold.

[0025] In this way, it can be ensured that repair or replacement of the affected component is initiated in good time prior to breakdown.

[0026] According to an additional form, the method is carried out continuously and/or in an event-controlled manner, wherein one or more sensors can be operated. This is to ensure that all occurring partial discharges or other damaging influences are detected. The term "temporally continuous measurement" as used herein is to mean a measurement which can also detect individual short signals in the range above a few milliseconds over a period of several hours, typically several days, or even several weeks and months. The method can be carried out, for example, in such a way that a first detector connected to the first optical fiber sensor and a second detector connected to the second optical fiber sensor continuously detect the optical signals supplied by the respective optical fiber sensor during a time period that can last for months, but the actual evaluation of the measurement or determination of the optical or mechanical variable correlated therewith takes place in an evaluation unit only when the signals change; that is, when the mechanical variable has changed, for example, as a result of an event, such as an electrical partial discharge. However, the actual evaluation of the measurement or determination of the optical and/or mechanical variables correlated therewith can also take place at periodic intervals. Through the continuous and/or event-controlled measurement by means of the first optical fiber sensor and the second optical fiber sensor, a continuous monitoring of field-induced light phenomena in the insulation, and of mechanical changes, and/or acoustic events in the insulation can be ensured.

[0027] According to one embodiment, a method for monitoring aging processes of insulation comprises the steps of monitoring light signals generated in the insulation with a first optical fiber sensor, monitoring deformations of the insulation and/or acoustic events in the insulation with a second optical fiber sensor, and estimating an aging status of the insulation. This method is typically carried out during ongoing operation of the high-voltage device, for example, a cable fitting; that is, under high-voltage conditions.

[0028] According to yet another exemplary embodiment, a high-voltage device is specified. The high-voltage device is designed to receive a high-voltage cable having a conductor configured to conduct electrical current and having a cable insulation surrounding the conductor. The high-voltage device comprises insulation designed to at least partially surround the cable insulation. The high-voltage device further comprises a first optical fiber sensor arranged at least partially in the interior of the high-voltage device and a second optical fiber sensor mechanically coupled to the insulation. The first optical fiber sensor is configured to detect an optical signal. In this case, the first optical fiber sensor may be configured to detect an electroluminescence and/or a discharge event with an apparent charge of less than approximately 5 pC, less than approximately 2 pC, or even less than 1 pC. For example, the first optical fiber sensor can have a measuring sensitivity which allows reliable signal detection, an electrical measurement still providing no evaluable results. This will occur in the case of apparent charges of less than 1 pC to approximately 0.1 pC. Electroluminescence and/or a discharge event during high-voltage operation can thus be detected markedly earlier, typically at least 10 times more sensitively than with established electrical and electromagnetic measuring methods. The second optical fiber sensor is configured to detect a mechanical variable. With the second optical fiber sensor, an electrical partial discharge occurring in the insulation can thus be detected via a deformation associated with the partial discharge and/or an oscillation of the insulation. Typically, the second optical fiber sensor is configured to detect an acoustic wave in the insulation. Thus, by using the first optical fiber sensor and the second optical fiber sensor, detection of changes in the insulation from a very early stage prior to the onset of partial discharges by means of the first optical fiber sensor up to the partial discharge range by means of the second optical fiber sensor can be ensured.

[0029] According to yet another exemplary embodiment, the high-voltage device is a switching device, for example, a switchgear cabinet, a cable sleeve, or a cable termination, the respective insulation of which is exposed to particularly high field strengths and is thus particularly susceptible to partial discharges. However, the high-voltage device can also be a generator, a voltage converter, for example, an inverter, or a transformer.

[0030] According to the invention, the high-voltage device comprises a field control part that is transparent or translucent at least in subregions and is configured to at least partially surround the cable insulation of the high-voltage cable. The field control part is typically a transparent or translucent elastomer field control body with an integrated deflector for changing the electric field profile in high-voltage devices, such as cable fittings. For this purpose, the field control part typically occupies the space in the high-voltage device in which the field strength during high-voltage operation is too high for the remaining insulation. The field control part can be designed in particular as a field control cone with an integrated conductive deflector. The field control part can thus guide the field lines during high-voltage operation of the high-voltage device, such that the field strength outside the field control part is sufficiently low. The conductive deflector can have a high absorption coefficient in the expected wavelength range of the electroluminescent event and/or discharge event and then represents a substantially non-transparent part of the field control part.

[0031] According to yet another exemplary embodiment, the first optical fiber sensor comprises an optical fiber doped with a fluorophore, typically a polymeric optical fiber with doped core, and an optical detector tuned to an emission wave spectrum of the fluorophore, and coupled to the doped optical fiber. The doped optical fiber is at least partially embedded into a transparent or translucent part of the insulation and/or arranged on a surface of the transparent or translucent part of the insulation. This enables a highly sensitive measurement of light signals in the insulation.

[0032] Further advantageous embodiments, details, aspects, and features of the present invention arise from the dependent claims, the description, and the enclosed drawings. The following is shown:

Fig. 1 a schematic cross-section of a high-voltage device according to one exemplary embodiment;

Fig. 2 a schematic cross-section of a high-voltage device according to another exemplary embodiment;

Fig. 3 a schematic cross-section of a high-voltage device according to yet another exemplary embodiment;

Fig. 4 a schematic cross-section of a high-voltage device according to yet another exemplary embodiment;

Fig. 5 a schematic cross-section of a high-voltage device according to another exemplary embodiment; and

Fig. 6 steps of a method for monitoring aging processes of the insulation of a high-voltage device according to one exemplary embodiment.

[0033] Fig. 1 shows a high-voltage device 100 for receiving a high-voltage cable 1 according to one exemplary embodiment in a schematic central cross-sectional view along the cylinder axis of the high-voltage cable 1. In the interior, the rotationally symmetrical high-voltage cable 1 contains a conductor 11 for conducting high-voltage current, for example, an aluminum, or copper conductor, which is surrounded by a cable insulation 12, typically VPE insulation (cross-linked polyethylene), and an outer cable shield 13, for example, an outer conductive layer or a semiconducting outer cable shield. Furthermore, the high-voltage cable 1 can additionally have cushioning layers, and a copper shield, and an outer jacket for protection against environmental influences. This can be a polyethylene jacket or a jacket made of another halogen-free material. Such components are not shown in Fig. 1 and the following figures for reasons of clarity. In addition, the high-voltage cable 1 may have an inner conductive layer between the conductor 11 and the VPE insulation. This inner conductive layer is likewise not shown.

[0034] The high-voltage device 100 illustrated in Fig. 1 represents a cable termination 100 such as is used, for example, in overhead lines. The cable termination 100 has a housing 110, for example, a ceramic housing, which closes off the internal parts of the high-voltage device 1 from the environment. An insulating region 2 is arranged inside the housing. The insulating region 2 can be formed, for example, by a largely transparent insulating space filled with oil or gas. The insulating region 2 forms a substantially cylindrically symmetrical region.

[0035] At the high-voltage cable 1 inserted into the cable termination, the outer layers (cable jacket, cushioning layers, and metallic shield) are removed, the typically semiconducting, outer cable shield 13 is continued into the region of the field control part, and then only the cable insulation 12 with the conductor 11 continues axially through the termination to the head fitting. Only the conductor 11 is guided completely through the cable termination 100 in order to be connected to the overhead line in the right-hand region of Fig. 1 after leaving the cable termination 100. Inside the cable termination 100, the conductor 11 is surrounded directly by the insulating region 2 only in the region of the removed cable insulation. In order to accommodate the high-voltage cable 1, a rotationally symmetrical, electrically insulating field control part 3 is inserted into the insulating region 2 and occupies the space within the insulating region 2 in which the electric field strength would be too great for the insulating materials in the insulating region 2. The field control part 3 has an inner hollow cylinder into which the high-voltage cable 1 can be inserted. For example, the field control part 3 may be designed as a field control cone. Typically, the field control part 3 is an elastomer field control part made of a transparent or translucent elastomer body; for example, a silicone elastomer body having sufficiently high transparency at one or more wavelengths from a range of approximately 300 nm to approximately 900 nm. The inner hollow cylinder is typically dimensioned such that there is an interference fit between the cable insulation 12 of the inserted cable 1 and the field control part 3, and the field control part 3 thus forms a stress cone. The insulating region 2 and the field control part 3 together form the insulation of the cable termination 100.

[0036] The field control part 3 and/or the high-voltage cable 1 may additionally be fixed, for example, by means of springs to the housing 110 or in a region 5 of the insulating region 2 at ground potential near the cable, for example, when the insulating region 2 is formed by a solid insulating body. Such fixation of field control part 3 and/or high-voltage cable 1 is typically used in a modular construction of the cable termination 100. Alternatively, the structure of the cable termination 100 can also be designed according to the wire-wrap technique or slip-on technique. Independent of the type of construction used, the insulation comprises a field control part 3 for receiving the cable 1 with partially removed cable insulation 12 and for suitable guidance of the field lines during high-voltage operation.

[0037] In order to reduce the electric field, an elastomer field control part 3 is typically used, into which an appropriately shaped conductive deflector 4 is integrated. The conductive deflector 4 is in electrical contact with the cable shield 13. Typically, the conductive deflector 4 also consists of a silicone elastomer, which, however, has a suitable electrical conductivity as a result of doping. Due to material inhomogeneities or faults, there are typically regions of increased field strength. These are represented in Fig. 1 by the regions 8 bordered by dashed lines. The probability of the occurrence or onset of partial discharges is increased in the regions 8 with increased field strength.

[0038] According to one exemplary embodiment, a first optical fiber sensor 20 and a second optical fiber sensor 30 are arranged in the interior of the high-voltage device 100. Both optical fiber sensors 20, 30 of the high-voltage device 100 are at least partially embedded into a transparent or at least translucent elastomer body 3, for example, a corresponding silicone elastomer body, which partially surrounds the insulation 12 of the high-voltage cable 1 and its conductor 11. The elastomer body 3 thus constitutes at least a part of the insulation of the high-voltage device 100.

[0039] The first optical fiber sensor 20 is a sensor for detecting an optical signal or light signal that may arise in the elastomer body 3 in the high-voltage field due change processes induced by high-voltage fields and caused by change carriers. The first optical fiber sensor 20 can in particular be configured to detect an electroluminescence signal and/or a light signal originating from a discharge event with apparent charges up to below 5 pC or below. The first optical fiber sensor 20 is typically a so-called "FOF sensor"; that is, it comprises a fluorescent optical fiber 20a, typically a fluorescent plastic optical fiber with doped core, and an optical detector tuned to the emission wave spectrum of the fluorophore of the doped core and coupled to the fluorescent optical fiber 20a. Typically, the absorption wave spectrum of the fluorophore is matched to the expected spectrum of the light signal in the elastomer body. Thus, an extremely sensitive sensor for optical signals can be provided. Moreover, the fluorescent optical fiber 20a is typically arranged with a plurality of coils around the region 8 with increased field strength, for example, in the form of a spiral helix as schematically shown in Fig. 1, such that much light can be collected from the particularly susceptible region 8, converted into long-wave light via the fluorophores, and supplied to the detector (not shown) in an evaluation unit 60. At least one end of the fluorescent optical fiber 20a is connected to the detector. The evaluation unit 60 is typically located in a field-free space 5 or outside the termination housing 110. The detector can thus be largely protected against electromagnetic interference of the high-voltage field. The detector is typically an optoelectrical transducer, for example, a photodiode, for example, an avalanche diode, or a photomultiplier. For silicone elastomers, for example, an avalanche diode with a maximum sensitivity in the range of approximately 800 nm can be used for detecting electroluminescent events. The fluorescent optical fiber 20a can be guided directly to the evaluation unit 60. However, it is also possible to connect the fluorescent optical fiber 20a to the evaluation unit 60 via a transport optical fiber 20b with less attenuation.

[0040] The conductive deflector 4 may be non-transparent due to its doping. In this case, as shown in Fig. 1, the fluorescent optical fiber 20a is typically arranged in the elastomer body 3, such that a sufficiently long section of the fluorescent optical fiber 20a is located outside the light shadow formed by the conductive deflector 4 for light signals emanating from the region 8 with increased field strength.

[0041] Moreover, it is also possible to embed not only one fluorescent optical fiber 20a having an absorption wavelength range, but also a plurality of such fluorescent optical fibers with matched absorption ranges at least partially in the elastomer body. A broader portion of the emission spectrum of partial discharges and/or electroluminescence can thereby be detected. Each of these fluorescent optical fibers can be connected via its own transport optical fiber to an individual detector, for example, an individual photodiode in the evaluation unit 60 adapted to the respective fluorophore. The signals of the individual photodiodes can then be simply added, for example, in order to determine an integral measure for the light output.

[0042] The second optical fiber sensor 30 is a sensor that can detect a mechanical variable in an adjacent medium, that is, for the exemplary embodiment illustrated in Fig. 1 in the elastomer body 3, and is mechanically coupled thereto for this purpose. The mechanical variable may be a deformation and/or an oscillation of the elastomer body 3 caused by a partial discharge. In particular, it can be an acoustic pressure, an acoustic frequency, and/or a frequency spectrum.

[0043] The second optical fiber sensor 30 can also be coupled via one or more supply fibers 53 to a detector in the evaluation unit 60 tuned to it and/or can be supplied with test signals, for example, laser signals, from or via the evaluation unit 60.

[0044] Due to the mechanical coupling between the field control part 3, the insulating region 2, and the cable insulation 12, acoustic events caused by partial discharges in the insulating region 2 or the cable insulation 12 can also typically be detected by the second optical fiber sensor 30.

[0045] According to one embodiment, the second optical fiber sensor 30 is a fiber tip sensor. The fiber tip sensor may consist of only one fiber tip or of a plurality of fiber tips. If a fiber tip is embedded into or at least adjoins an optically transparent or translucent medium, such as a silicone elastomer as cable insulation, the optical refractive index and thus the density of the adjacent elastomer can be deduced on the basis of the light backscattered at the interface between fiber core and medium. Thus, density changes and/or oscillations of the elastomer can be detected optically via the backscattered light.

[0046] Typically, the second optical fiber sensor 30 is a phase-sensitive sensor, such as an interferometric sensor. The optical fiber sensor 30 can, for example, be a Fabry-Perot interferometer. Particularly sensitive measurements can thus be realized.

[0047] The optical fiber sensor 30 can also be a fiber Bragg grating sensor with which, in particular, Lamb waves, that is, mixed pressure and shear waves, can be detected. The fiber Bragg grating sensor is typically designed such that it can detect irreversible deformations of the field control part 3 and/or acoustic events. Irreversible deformations of the field control part 3 can be caused by electrical partial discharges, but can also precede electrical partial discharges. For example, in the case of very large terminations with dimensions of up to a few meters, mechanical setting phenomena of the correspondingly heavy components can occur. This can be associated with stresses or deformations of the field control part 3, which themselves can promote or initiate electrical partial discharges. Structure damages causing electrical partial discharges can thus also be detected with a fiber Bragg grating sensor.

[0048] However, the optical fiber sensor 30 may also be a quasi-distributed optical fiber sensor. The latter consists of a fiber with a plurality of measurement points, which are at regular distances from one another. Via time-based backscatter measurements, changes causing irreversible deformations and thus also partial discharges in the field control part 3 can be detected in sections along the fiber in the field control part 3.

[0049] Both optical fiber sensors 20, 30 are typically designed in such a way that they consist only of dielectric materials, for example, glass or polymer material, and therefore do not or only insignificantly change the electric field distribution in the cable termination 100. Moreover, such optical fiber sensors are practically not affected by external electromagnetic fields. As such, the optical fiber sensors 20, 30 can also be positioned in the vicinity of regions 8 of particularly high field strength and therefore in the vicinity of risk areas in order to detect electroluminescent events and/or partial discharges. Sensitive monitoring of the aging status during operation, that is, under high-voltage conditions, can thus be ensured. This increases the safety of the operation of high-voltage plants. In addition, the measurement results or the measurement signals can be forwarded via one or more optical supply fibers 50 to a central monitoring location, such that complex measurement campaigns on site can be dispensed with. Due to the low fiber attenuation, even optical fiber measurements over great distances from a central monitoring location are possible.

[0050] If the effective dielectric constant of the optical fiber sensors 20, 30 deviates from the dielectric constant of the elastomer body 3, a change in the electric field distribution in the elastomer body 3 can occur. It can then additionally be provided that the shape and/or conductivity of the field control cone 4 is modified in such a way that the change in the electric field is compensated by the optical fiber sensors 20, 30 and/or the optical supply fibers 53.

[0051] In comparison to electromagnetic or piezoelectric sensors or measurement setups arranged outside the high-voltage device, the combined measurement of optical signals and mechanical variables with optical fiber sensors 20, 30, which are tailored to the respective measurement and which are also typically arranged close to the critical regions 8, enables a simpler, and/or more sensitive, and/or earlier detection of aging processes caused by high-voltage fields in the insulation 3.

[0052] The first optical fiber sensor 20 may additionally or alternatively be configured to detect a light signal of a partial discharge of the elastomer body 3 or to forward it to the external evaluation unit. Partial discharges can thus be detected by the first optical fiber sensor 20 and by the second optical fiber sensor 30; that is, with independent sensors or methods. Incorrect measurements can be at least reduced and/or the partial discharge can be better characterized by correlating the independent measurement results. For example, if only the second optical fiber sensor 30 detects a signal indicative of a partial discharge, but the first optical fiber sensor 20 does not detect a light signal associated therewith, this may be an indication of an external mechanical effect or disturbance, particularly when the first optical fiber sensor 20 later measures a partial discharge signal together with the second optical fiber sensor 30.

[0053] Fig. 2 shows a high-voltage device 101 for receiving a high-voltage cable 1 according to one exemplary embodiment in a schematic central cross-sectional view along the cylinder axis of the high-voltage cable 1. The high-voltage device 101 is similar to the high-voltage device 100 and also constitutes a cable termination. The fluorescent optical fiber 20a of the first optical fiber sensor 20 is, however, arranged in the case of the cable termination 101 on a surface of the elastomer body 3, that is, wound around the elastomer body 3 where it can likewise collect a light signal arising in the elastomer body 3, convert it, and pass it to the detector in the evaluation unit 60. For detection, the fluorescent optical fiber 20a can even be arranged at least partially in the insulating region 2 if the latter is transparent or translucent; that is, for example, it is formed by a transparent epoxy resin body or silicone body.

[0054] Fig. 3 shows a high-voltage device 102 for receiving a high-voltage cable 1 according to one exemplary embodiment in a schematic central cross-sectional view along the cylinder axis of the high-voltage cable 1. The high-voltage device 102 is similar to the high-voltage device 100 and also constitutes a cable termination. However, the second optical fiber sensor 30 is arranged in the case of the cable termination 102 on a surface of the elastomer body 3 in the field-free region 5, where it can also measure a mechanical variable, for example, a variable characterizing an acoustic event. Alternatively, the second optical fiber sensor 30 may also be partially embedded in the elastomer body 3.

[0055] Fig. 4 shows a high-voltage device 103 for receiving a high-voltage cable 1 according to one exemplary embodiment in a schematic central cross-sectional view along the cylinder axis of the high-voltage cable 1. The high-voltage device 103 is similar to the high-voltage device 100 and also constitutes a cable termination. However, the second optical fiber sensor 30 in the case of the cable termination 103 is embedded into an insulating body forming the insulating region 2, where it can also measure a mechanical variable, for example, a sound level and/or an acoustic frequency, which can also be used for detecting a partial discharge in the elastomer body 3 or the cable insulation 12, due to the mechanical coupling between the insulating body and the elastomer body 3 and the cable insulation 12.

[0056] Fig. 5 shows a high-voltage device 200 for receiving two high-voltage cables 1 and 22 according to one exemplary embodiment in a schematic central cross-sectional view along the cylinder axes of the coaxially oriented high-voltage cables 1 and 22. The rotationally symmetrical high-voltage cables 1, 22 each comprise a conductor 11 and 112 respectively for conducting high-voltage current and a cable insulation 12, 122 surrounding the respective conductor 11, 112. The high-voltage device 200 is a high-voltage cable sleeve for connecting two high-voltage cables. The cable sleeve 200 has a housing 210, for example, a metal housing, in which the high-voltage cables 1 and 22 are arranged centrally. A complex elastomer sleeve cone with field control parts 3, 32, which are embedded into an insulating region 2 and which reduce in a defined manner the high-voltage field respectively occurring at the joined cable ends, takes over the field control of the high-voltage cables 1 and 22 to be connected. The insulating region 2 of the cable sleeve 200 is typically formed by a cast resin insulator or a silicone body. Furthermore, the insulation and field control is to be restored in the region of the connected metallic conductors 11, 112. This takes place, for example, via a crimping connection and with a weakly conductive polymer ring 7, which are likewise embedded into the insulating region 2. The typically rotationally symmetrical insulation 2, 3, 32 of the cable sleeve 200 is formed by the field control parts 3, 23 and the insulating region 2. Moreover, the insulating region 2 may be terminated by an outer, conductive sleeve coating (not shown) which is arranged on the outer surface of the insulating region 2, wherein a small gap to the housing 210 may remain, and which, together with the cable shields 13, 132, is at ground potential. The field control parts 3, 32 are typically transparent or translucent elastomer field control parts 3, 32, into which a respective conductive deflector 4, 42 is integrated.

[0057] The cable sleeve 200 may be constructed modularly in the extrusion technique or according to the wire-wrap technique or the slip-on technique. In this way, the insulation of the cable sleeve can modularly consist of a continuous elastomer field control part with integrated deflectors 4, 42, which takes up the space of the field control parts 3, 32, and of the insulating region 2 shown in Fig. 5, wherein a small gap to the housing 210 may remain, and which is terminated by an outer, conductive sleeve coating to ground potential. However, irrespective of the manufacturing technique, the insulation comprises at least one field control part 3, 32 for receiving the cables 1, 22 with cable insulation 12, 122 removed at the respective cable ends, and for suitable guidance of the field lines during high-voltage operation.

[0058] According to one exemplary embodiment, a first optical fiber sensor 20, 21 and a second optical fiber sensor 30, 31 as described with reference to Figs. 1 to 4 are respectively at least partially embedded into the field control parts 3, 32. This means that the first optical fiber sensors 20, 21 of the high-voltage sleeve 200 are also sensors for detecting optical signals or light signals arising in the insulation 2, 3, 32 and in particular in the elastomer bodies 3, 32 in the high-voltage field. Typically, the first optical fiber sensors 20, 21 are FOF sensors. For reasons of clarity, however, the reference signs for the fluorescent optical fibers and the optionally used transport optical fibers for connecting to an evaluation unit, which is likewise not shown, are dispensed with in Fig. 5. The second optical fiber sensors 30, 31 of the cable sleeve 200 are sensors which can detect a deformation, in particular an oscillating deformation, for example, an oscillation, of the respectively surrounding medium. Partial discharges occurring in the insulation of the cable sleeve 200 can thus be reliably detected and easily observed over longer periods of time during high-voltage operation. As such, the first and second optical fiber sensors 20, 21, 30, 31 also enable simple, and/or sensitive, and/or much earlier detection of aging processes caused by high-voltage fields in the insulation.

[0059] It is understood that the second optical fiber sensors 30, 31 may also be arranged at least partially in the insulating region 2 and/or on a surface of the insulating region 2. If the insulating region 2 is formed by a transparent or translucent insulating body, for example, a transparent epoxy resin body, the first optical fiber sensors 20, 21 may likewise be arranged at least partially in the insulating region 2 and/or on a surface of the insulating region 2.

[0060] Moreover, more than two first optical fiber sensors 20, 21 and/or more than two second optical fiber sensors 30, 31 may be arranged at least partially in the insulation 2, 3, 32 of the high-voltage sleeve 200 or on surfaces of the insulation 2, 3, 32. This makes it possible to provide a more accurate and/or more fault-tolerant monitoring of aging statuses of the cable sleeve. For example, by using a plurality of FOF sensors matched in their absorption spectrum as first optical fiber sensors 20, 21, the measuring sensitivity can be further increased.

[0061] Exemplary embodiments of cable fittings were described with reference to Figs. 1 to 5. In other exemplary embodiments, the high-voltage device is a switching device, a generator, or a voltage converter, for example, a transformer, having a transparent or translucent insulation, a first optical fiber sensor arranged in the interior the high-voltage device for detecting an optical signal in the insulation, and a second optical fiber sensor mechanically coupled to the insulation in order to detect a mechanical variable of the insulation. Even in such high-voltage devices, by using the two optical fiber sensors using independent physical principles, reliable monitoring of aging processes of the insulation can take place from a very early stage prior to the onset of the partial discharges, which permanently damage the material of the insulation, up to the range of the partial discharges. Such methods will be explained in detail below.

[0062] Fig. 6 illustrates steps of a method 1000 for monitoring aging processes of the insulation of a high-voltage device according to one exemplary embodiment. The high-voltage device contains insulation, which is transparent or translucent at least in parts, for receiving a high-voltage cable. A first optical fiber sensor for detecting a light signal is arranged in the interior of the high-voltage device. In addition, a second optical fiber sensor for measuring mechanical variable is mechanically coupled to the insulation. For example, the high-voltage device can be one of the high-voltage devices explained with reference to Figs. 1 to 5.

[0063] In a first block 1100, a measurement 1110 of a light signal generated in the insulation with the first optical fiber sensor and/or a measurement 1120 of a mechanical variable of the insulation with the second optical fiber sensor takes place. The measurement results of both measurements 1110, 1120 are typically queried in block 1100. The presence of no new or changed measurement result also corresponds to a measurement in this case.

[0064] The measurement 1110 may comprise the measurement of a light intensity, one or more wavelengths of light, and/or a pulse duration of an electroluminescence occurring in the insulation, and/or a partial discharge occurring in the insulation. The first optical fiber sensor may be broadband or tuned sensitively to the expected light signal. The first optical fiber sensor can thus be tuned in a manner selective to wavelength to the expected electroluminescence signal, given the material of the insulation and given the voltage. However, the first optical fiber sensor may also be tuned in a manner selective to wavelength to the expected partial discharge signal, given the material of the insulation and given the voltage. It is thus possible to detect the respective signals particularly sensitively and/or precisely. This is particularly important for the typically relatively weak electroluminescence signals, so that they can be detected as early as possible. The measurement 1110 may also be performed by a plurality of first optical fiber sensors that are selective for various wavelengths or wavelength ranges.

[0065] Moreover, the first optical fiber sensor(s) are typically at least partially embedded into the insulation and are thus arranged relatively close to the regions of the highest electric field strengths. The sensitivity of the measurement 1100 can thereby be further increased.

[0066] The measurement 1120 typically comprises the measurement of a pressure, a voltage, a deformation, an oscillation in the insulation, and/or a variable characterizing an acoustic event. In one exemplary embodiment, the measurement 1120 is in the frequency range of approximately 10 kHz to approximately 5 MHz, particularly in the range of approximately 10 kHz to approximately 500 kHz, or a portion thereof. Such frequency ranges are characteristic of acoustic events caused by partial discharge in the insulation. The measurement 1120 may also be performed by means of a plurality of second optical fiber sensors, which may be selective for various frequencies or frequency ranges.

[0067] Typically, the measurement 1120 is carried out sensitively to partial discharges in the insulation, and the measurement 1110 is carried out sensitively to changes preceding partial discharges in the insulation. Monitoring of the aging status can thus be ensured from a very early aging status up to the partial discharge range.

[0068] According to one exemplary embodiment, the measurements 1110 and/or 1120 are each performed with a plurality of optical fiber sensors, which increases the reliability of the measurement and may be used to more accurately determine the location and time of the event. In order to be able to determine the three spatial coordinates and the time course of the events, at least four sensors, which may also be selective in the same frequency ranges or wavelength ranges, are required.

[0069] According to another exemplary embodiment, the measurements 1110 and 1120 are performed temporally continuously in block 1100 and during ongoing operation of the high-voltage device. Changes in the insulation can thus be tracked without gaps. The term "temporally continuous measurement" as used herein is to mean a measurement which can also detect individual short signals in the range above a few milliseconds over a period of several hours, typically several days, or even several weeks and months. However, the measurements 1110 and 1120 in block 1100 may also take place in a time-limited manner during a test phase in which the high-voltage device is subjected to electrical test signals.

[0070] According to yet another exemplary embodiment, the measurements 1110 and 1120 are controlled and monitored by a central evaluation unit. Aging statuses of the insulation of various high-voltage devices can thus be monitored in parallel.

[0071] If a light signal was detected in measurement 1110 and/or if a changed or changing mechanical variable, for example, a changed length, changed mechanical stress, or an acoustic event, was detected in measurement 1120 in block 1110, a probability for the occurrence of an electroluminescence and/or partial discharge as well as its intensity can be determined, depending on the measurement result, in a subsequent block 1200. For example, an electroluminescent event in the insulation can be inferred from a slightly fluctuating light signal of the measurement 1110. On the other hand, a discharge event in the insulation can be inferred from a sufficiently strongly fluctuating light signal of the measurement 1110, wherein the detected light quantity and/or pulse duration can serve as a measure for the intensity of the discharge event. Depending on the material of the insulation and field strength, an equivalent apparent discharge can also be determined via calibration curves, and the occurrence of a partial discharge can thus be detected and quantified. Analogously, a characteristic fluctuation of an acoustic event detected in measurement 1120 can be used to infer the occurrence of a partial discharge, wherein a measured acoustic frequency, an integral sound power, and/or the measured acoustic pressure, and/or the measured acoustic duration can likewise be used to characterize the partial discharge intensity.

[0072] Block 1200 may alternatively or additionally also be performed periodically. If no light signal was measured during a time period in block 1110 upon measurement 1110 and no changed or changing mechanical variable was measured upon measurement 1120, it is typically assumed that neither an electroluminescent event nor a discharge event has occurred in the insulation.

[0073] In a block 1300, an estimation of an aging status of the insulation then takes place. This is typically carried out periodically and/or when an electroluminescent event or a discharge event was detected or classified in its intensity in block 1200. Moreover, block 1300 as well as block 1200 are also typically performed by the central evaluation unit. If neither an electroluminescent event nor a discharge event were detected in block 1200, it is typically assumed that the aging status of the insulation did not change. Otherwise, an estimation of the aging status of the insulation takes place. In this case, the signals measured in block 1100 can be correlated with one another and/or with earlier measurement results in order to further increase the measuring accuracy. Depending on the measurement, the aging status of the insulation is adjusted. Typically, upon the occurrence or ongoing occurrence of electroluminescence, the aging status is only slightly adjusted. On the other hand, when partial discharges occur, the aging status is typically adjusted more strongly, wherein stronger partial discharges typically lead to a stronger adjustment of the aging status. For estimating an advanced aging status of the insulation, in particular the length of a partial discharge tree in the insulation can be taken into account, which can be determined, for example, with a plurality of second optical fiber sensors.

[0074] According to yet another exemplary embodiment, a comparison of the determined aging status of the insulation with a threshold takes place in a further step 1400. This threshold may be, for example, a degree of change or a degree of damage, such as the magnitude of a partial discharge or of a partial discharge tree, the size of an electroluminescent region, or some other type of variable negatively correlated with the expected remaining time to electrical breakdown. If the aging status exceeds this threshold, a warning message is typically output in a further step 1500. Depending on the threshold and the distance between the aging status and the threshold, the warning message can also take place in stages of increasing urgency. Thereafter, a new monitoring cycle typically begins. Continuous monitoring of the aging status of the insulation during high-voltage operation can thus be provided. The monitoring can also be carried out by a central evaluation unit in a controlled manner in parallel at a plurality of insulation materials.

[0075] In the case of a newly installed insulation or a newly installed high-voltage device, only optical signals of an electroluminescence are typically initially measured at the insulation after a certain period of time, which signals represent a measure for a low degree of change or for a long period of time up to the expected electrical breakdown. As long as only electroluminescent events are detected, a further long lifetime of the insulation is to be assumed because of lack of partial discharges. Accordingly, only a low-urgency warning signal is typically output in step 1500. However, constant electroluminescence typically leads to low-intensity discharges via the associated erosion processes, such as microcavity formation, expansion of the cavities beyond critical dimensions. Accordingly, as the duration of the electroluminescence increases, the level of urgency of the warning message is typically increased. If a partial discharge is detected for the first time at a later point in time, for example, by the second optical fiber sensor via a sound measurement, the level of urgency of the warning message is also typically increased. With the onset of growth of the partial discharge trees, the acoustic intensity typically increases and/or the sound spectrum changes. The duration and/or frequency of partial discharges can also increase in this case. With increasing intensity, frequency, changed frequency spectrum, and/or time duration of the detected signal at the second optical fiber sensor, the level of urgency of the warning message is typically increased further accordingly. Replacement parts can thus be ordered in good time, depending on inventory levels. The highest warning level is typically reached at the latest when the electric partial discharge trees have reached a critical size, and repair or replacement should be initiated in order to prevent breakdown. This makes it possible to effectively avoid great economic damages and the risk of injury to plant personnel as a result of the destruction of the material of the insulation.

[0076] The prediction accuracy of the aging status can be further increased by correlating the measurements of a plurality of first and/or second optical fiber sensors. For example, the position and/or the growth of discharge trees can be monitored by using the measurement data of a plurality of second optical fiber sensors. The time and location of an impending breakdown can thus be determined more precisely. By early detection of partial discharge trees or their growth and timely repair, it is possible to prevent the formation of critical destruction structures which initiate a breakdown. Analogously, by using the measurement data of electroluminescent events of a plurality of first optical fiber sensors, the previously damaged volume of the insulation and/or its growth can be monitored. The location and time of an imminent partial discharge can thus be determined more precisely.

[0077] The present invention was explained with reference to exemplary embodiments. Such exemplary embodiments should in no way be understood as limiting the present invention.

Patentkrav

1. Fremgangsmåde til overvågning af ældningsprocesser af en isolering (2, 3, 32) i en højspændingsindretning (100, 101, 102, 103, 200), omfattende:
- måling af et lyssignal, som er genereret i isoleringen (2, 3, 32), med en første fiberoptisk sensor (20, 21), hvor den første fiberoptiske sensor (20, 21) omfatter en fluorescensoptisk lysledefiber, hvor isoleringen (2, 3, 32) omfatter en feltstyredel (3, 32), som er transparent eller translucent i det mindste i delområder, og som er indrettet til i det mindste delvist at omgive en kabelisolering (12, 122) af et højspændingskabel (1, 22), og hvori den første fiberoptiske sensor (20, 21) er i det mindste delvist indlejret, og/eller på hvis overflade den første fiberoptiske sensor (20, 21) er i det mindste delvist anbragt, hvor målingen af lyssignalet, som er genereret i isoleringen (2, 3, 32), omfatter målingen af en lysintensitet, en lysbølgelængde og/eller en pulsvarighed af en elektroluminescenshændelse, som opstår i feltstyredelen (3, 32), og/eller en afladningshændelse, som opstår i feltstyredelen (3, 32), med en tilsyneladende ladning på mindre end ca. 5 pC;
- måling af en mekanisk størrelse af isoleringen (2, 3, 32) med en anden fiberoptisk sensor (30, 31), som er mekanisk koblet med isoleringen (2,3,32); og
- estimering af en ældningstilstand af isoleringen (2, 3, 32).

2. Fremgangsmåde ifølge krav 1, hvor den anden fiberoptiske sensor (30, 31) er en fasefølsom sensor.

3. Fremgangsmåde ifølge krav 1 eller 2, hvor målingen af lyssignalet, som er genereret i isoleringen (2, 3, 32), omfatter målingen af en lysintensitet, en lysbølgelængde og/eller en pulsvarighed af en delafladningshændelse, som opstår i feltstyredelen (3, 32).

4. Fremgangsmåde ifølge et af de foregående krav, hvor målingen af den mekaniske størrelse er målingen af et tryk, en spænding, en deformering, en størrelse, som karakteriserer en svingning, og/eller en størrelse, som karakteriserer en lydhændelse.

5. Fremgangsmåde ifølge et af de foregående krav, hvor målingen af den mekaniske størrelse og/eller målingen af lyssignalet, der er genereret i isoleringen (2, 3, 32), udføres tidsmæssigt kontinuerligt og/eller på en hændelsesstyret måde.

6. Fremgangsmåde ifølge et af de foregående krav, hvor fremgangsmåden udføres, mens højspændingsindretningen (100, 101, 102, 103, 200) er i drift.

7. Fremgangsmåde ifølge et af de foregående krav, hvor estimeringen af en ældningstilstand af isoleringen (2, 3, 32) tager højde for mindst en af de følgende størrelser:
- et lydtryk af en lydhændelse, som opstår i isoleringen (2, 3, 32);
- en lydfrekvens af en lydhændelse, som opstår i isoleringen (2, 3, 32);
- en lydvarighed af en lydhændelse, som opstår i isoleringen (2, 3, 32);
- en integreret lysintensitet af lyssignalet, som er genereret i isoleringen (2, 3, 32);
- en fluktuation af en lysintensitet af lyssignalet, som er genereret i isoleringen (2, 3, 32); og
- en længde af et delafladningstræ i isoleringen (2, 3, 32).

8. Fremgangsmåde ifølge et af de foregående krav, yderligere omfattende:
- detektion af en delafladningshændelse i isoleringen (2, 3, 32); og/eller
- detektion af en elektroluminescenshændelse i isoleringen (2, 3, 32); og/eller
- afgivelse af en advarselsmelding, når ældningstilstanden af isoleringen (2, 3, 32) overskrider en på forhånd angivet tærskelværdi.

9. Højspændingsindretning (100, 101, 102, 103, 200) til optagelse af et højspændingskabel (1, 22) med en leder (11, 112), som er indrettet til at lede elektrisk strøm, og en kabelisolering (12, 122), som omgiver lederen (11, 112), omfattende:
- en isolering (2, 3, 32), som er indrettet til delvist at omgive kabelisoleringen (12, 122), hvor isoleringen (2, 3, 32) omfatter en feltstyredel (3, 32), som er transparent eller translucent i det mindste i delområder, og som er indrettet til i det mindste delvist at omgive kabelisoleringen (12, 122);

- en første fiberoptisk sensor (20, 21), som er i det mindste delvist anbragt i det indre af højspændingsindretningen (100, 101, 102, 103, 200) og er indrettet til at detektere et lyssignal i isoleringen (2, 3, 32), hvor den første fiberoptiske sensor (20, 21) omfatter en lyslederfiber (20a), som er doteret med en fluorofor, hvor den doterede lyslederfiber (20a) er i det mindste delvist indlejret i feltstyredelen (3) og/eller anbragt på en overflade af feltstyredelen (3), hvor det i isoleringen genererede lyssignal er et lyssignal af en elektroluminescenshændelse i feltstyredelen (3) og/eller er et lyssignal genereret af en afladningshændelse med en tilsyneladende ladning på mindre end 5 pC i feltstyredelen (3); og
- en anden fiberoptisk sensor (30, 31), som er mekanisk koblet med isoleringen (2, 3, 32), og som er indrettet til at detektere en mekanisk størrelse.

10. Højspændingsindretning (100, 101, 102, 103, 200) ifølge krav 9, hvor højspændingsindretningen (100, 101, 102, 103, 200) er en kabelmuffe (200), en kabelendelukning (100, 101, 102, 103), en generator, en spændingstransformer eller et fordelingsanlæg.

11. Højspændingsindretning (100, 101, 102, 103, 200) ifølge krav 9 eller 10, hvor den anden fiberoptiske sensor (30, 31) er en fasefølsom sensor.

12. Højspændingsindretning (100, 101, 102, 103, 200) ifølge krav 11, hvor den anden fiberoptiske sensor (30, 31) er i det mindste delvist indlejret i feltstyredelen (3, 32) og/eller anbragt på en overflade af feltstyredelen (3, 32).

13. Højspændingsindretning (100, 101, 102, 103, 200) ifølge et af kravene 9 til 12, hvor den anden fiberoptiske sensor (30, 31) er indrettet til at detektere en delafladning i feltstyredelen (3, 32) og/eller en deformering af isoleringen (2, 3, 32) og/eller en lydbølge i isoleringen (2, 3, 32).

14. Højspændingsindretning (100, 101, 102, 103, 200) ifølge et af kravene 9 til 13, hvor den første fiberoptiske sensor (20, 21) omfatter en optisk detektor, som er tilpasset et emissionsbølgespektrum af lyslederfibrenes (20a) fluorofor og koblet med den doterede lyslederfiber (20a), og/eller hvor lyslederfibrene (20a) udgør en flerhed af viklinger omkring et område (8) med øget feltstyrke i feltstyredelen (3) under en højspændingsdrift af højspændingsindretningen.

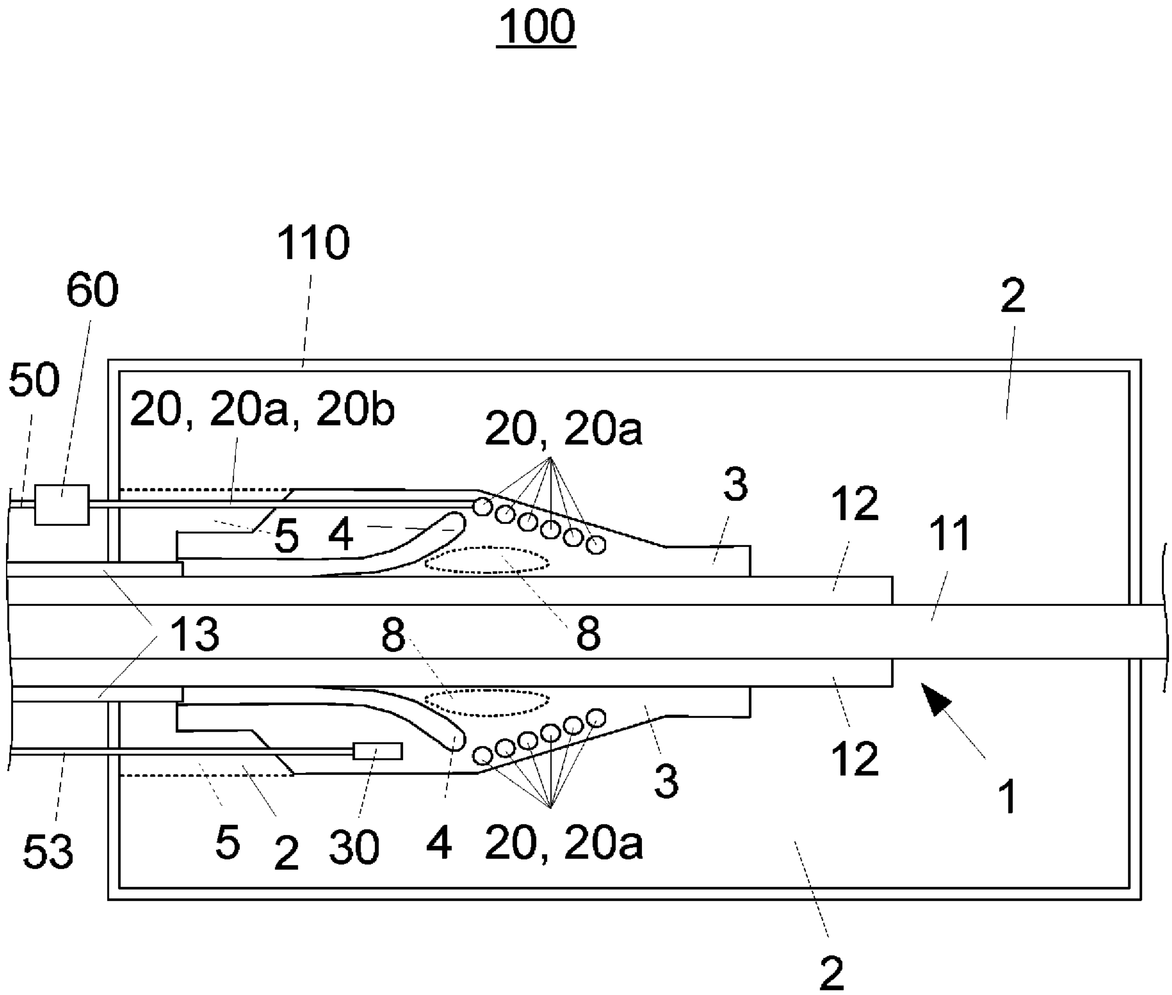
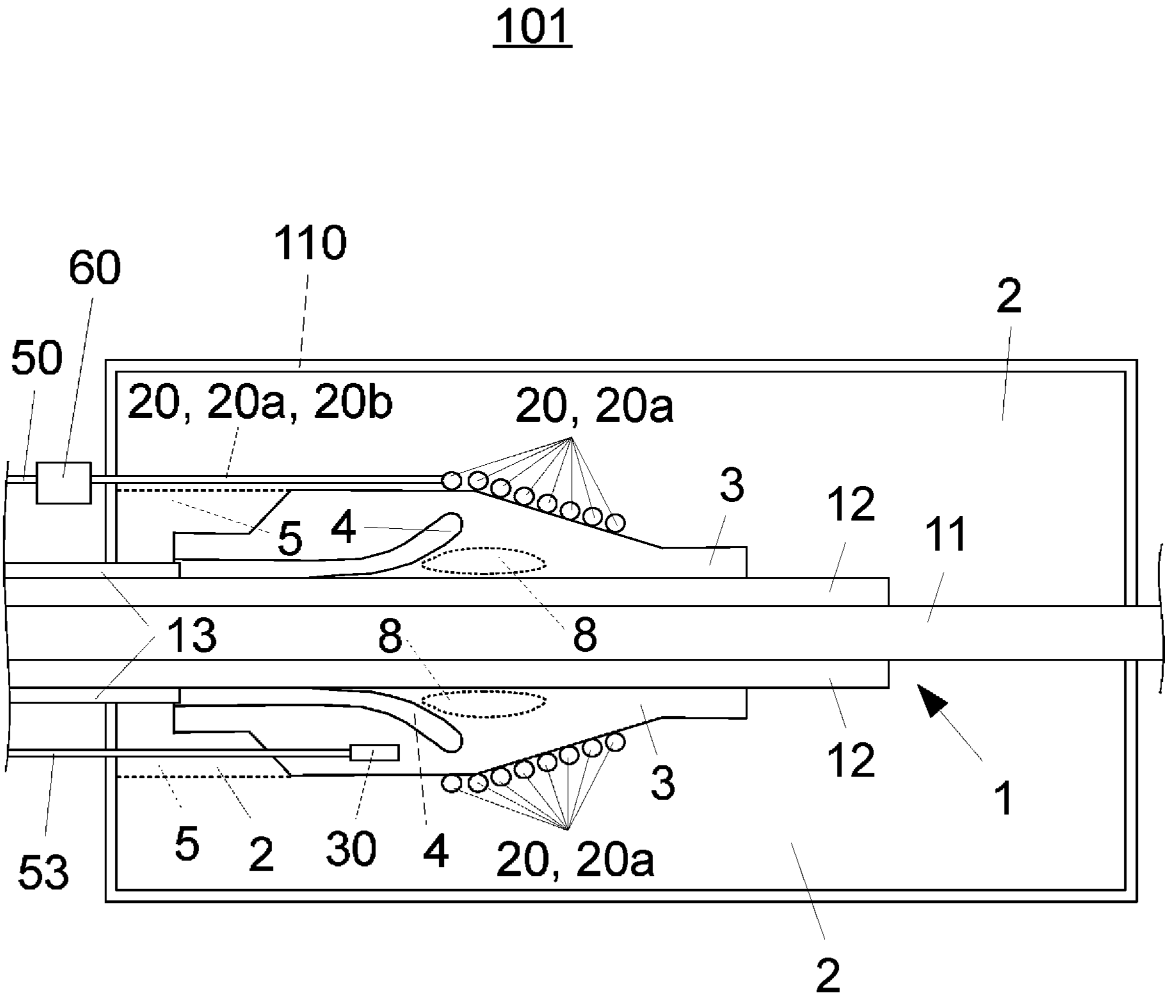

100
110
60
50
2
20, 20a, 20b
20, 20a
5
4
3
12
11
13
8
8
12
3
1
53
5
2
30
4
20, 20a
2

Fig. 1


101
110
60
50
2
20, 20a, 20b
20, 20a
3
12
11
5
4
13
8
8
12
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5
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30
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20, 20a
53
2

Fig. 2

102

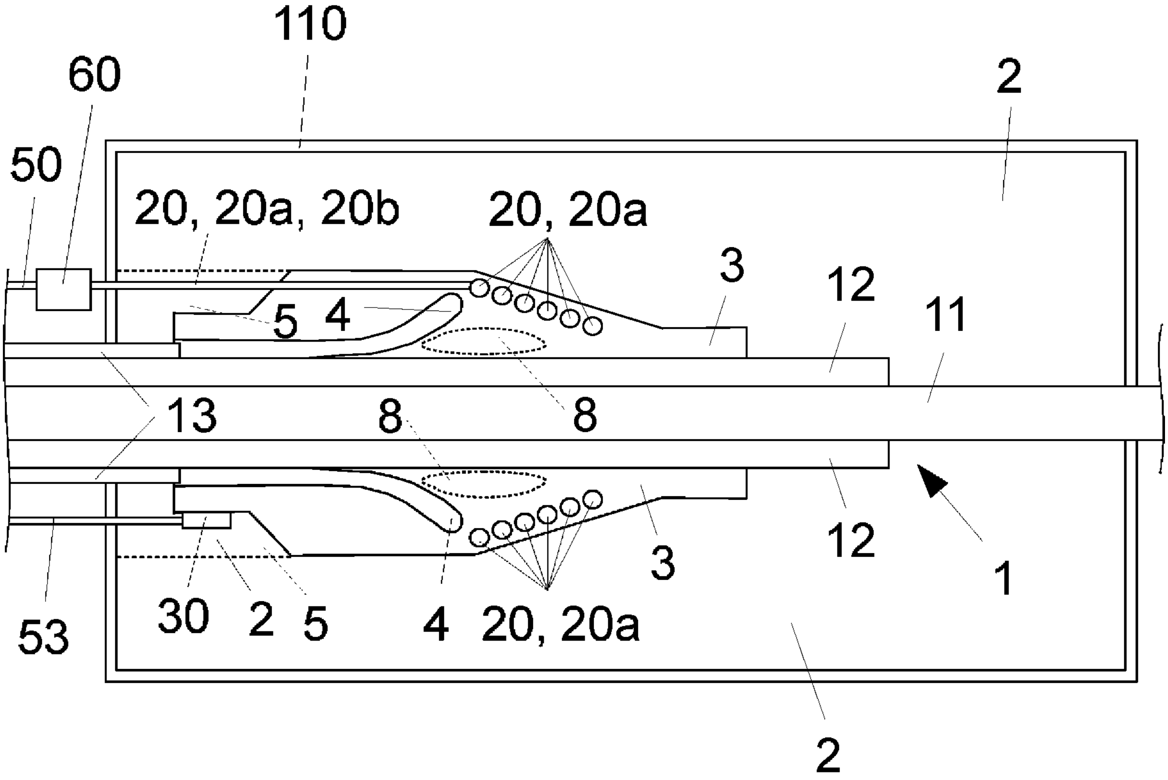

Fig. 3

103

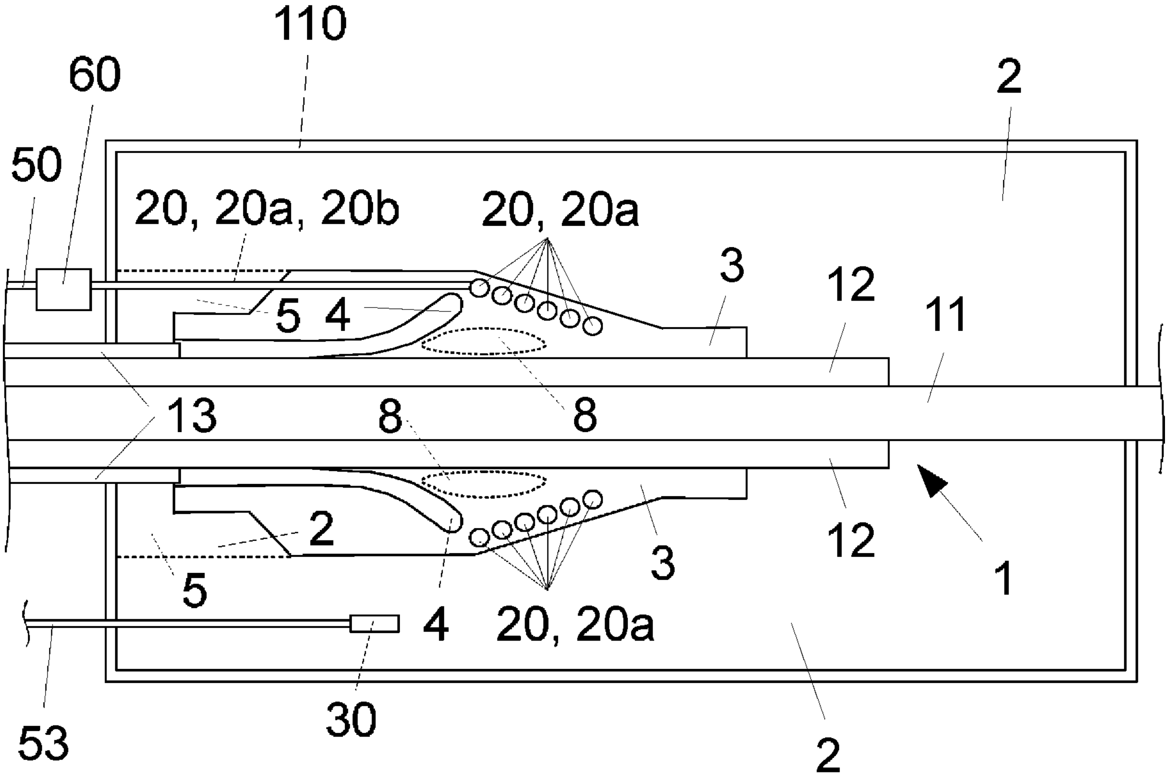

Fig. 4

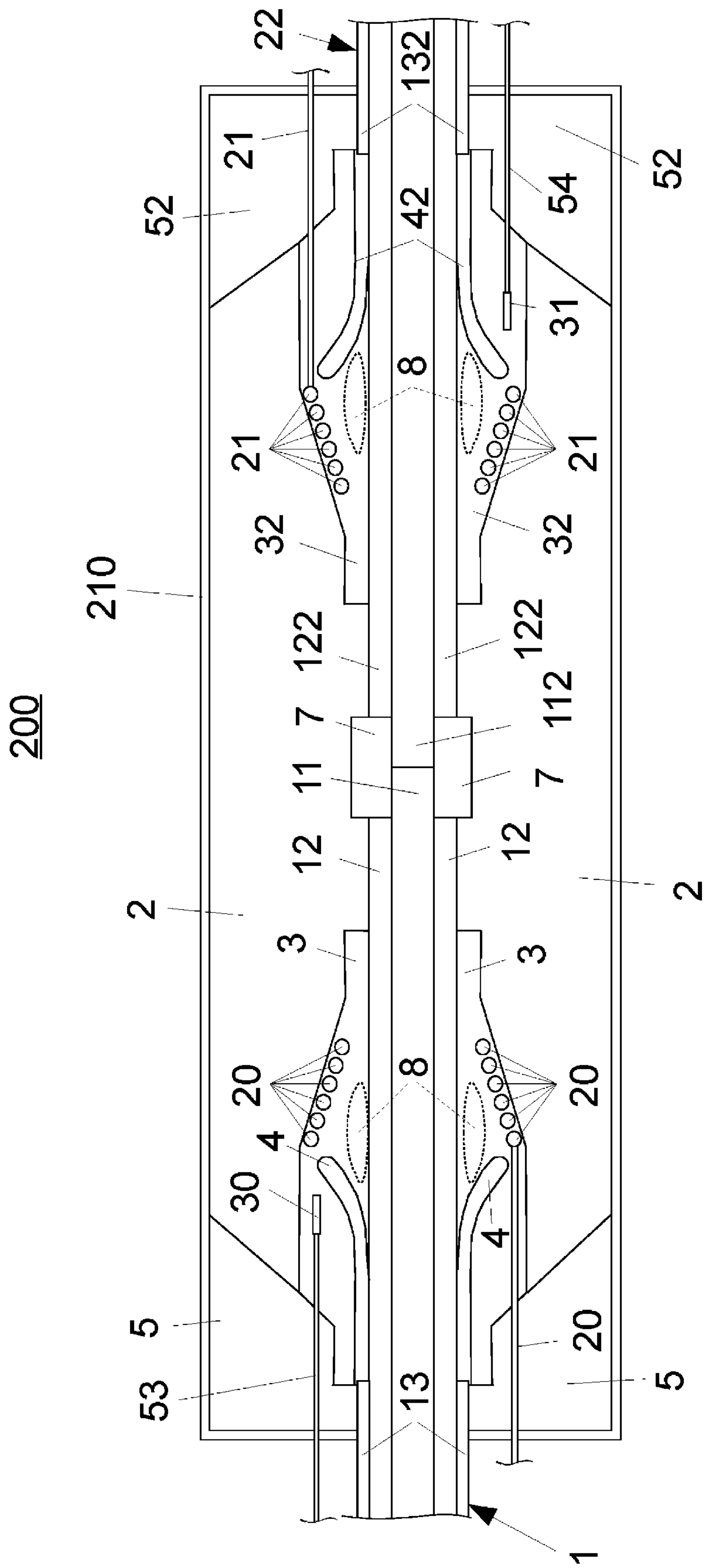

Fig. 5

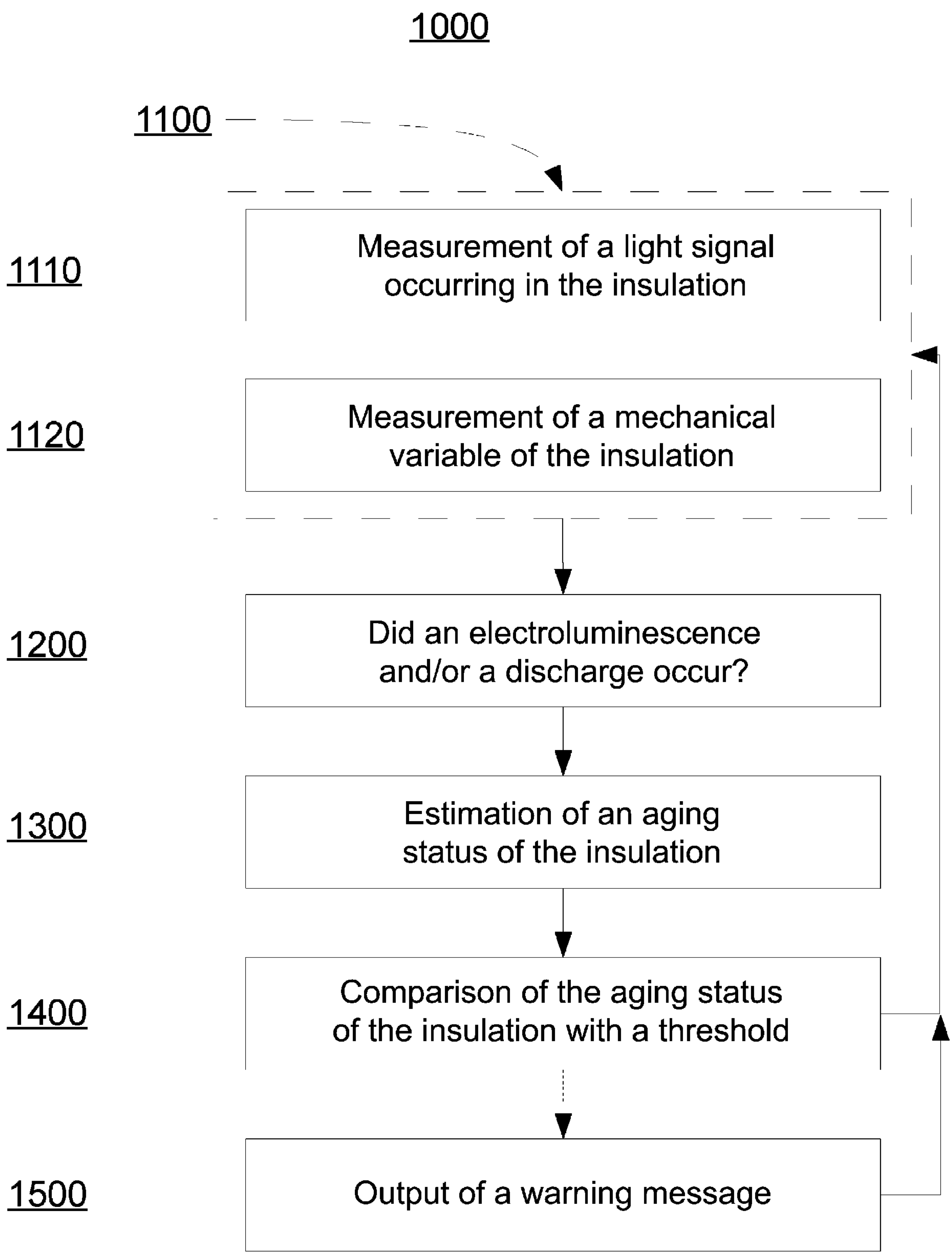
1000
1100
1110
Measurement of a light signal occurring in the insulation
1120
Measurement of a mechanical variable of the insulation
1200
Did an electroluminescence and/or a discharge occur?
1300
Estimation of an aging status of the insulation
1400
Comparison of the aging status of the insulation with a threshold
1500
Output of a warning message

Fig. 6